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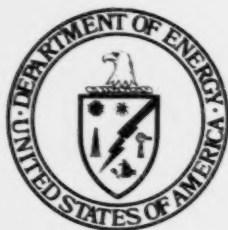
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Engineering/Economic Analysis of Coal Preparation with Flue Gas Desulfurization for Keeping Higher Sulfur Coals in the Energy Market

March 1982



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U.S. Department of Energy
Assistant Secretary for Fossil Energy
Office of Coal Utilization and Extraction

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Engineering/Economic Analysis of Coal Preparation with Flue Gas Desulfurization for Keeping Higher Sulfur Coals in the Energy Market

March 1982



Prepared by:
Hoffman-Holt, Incorporated
Silver Spring, MD 20910
Under Contract No. DE-AC01-80ET15295

Prepared for:
U.S. Department of Energy
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PREFACE

This report was prepared by Hoffman-Holt Incorporated of Silver Spring, Maryland, under U.S. Department of Energy Contract Number DE-AC01-80ET15295. It was administered under the technical direction of Mr. William Fedarko in the Office of Coal Utilization and Extraction. Mr. Richard Maling was the contract administrator for the Department of Energy.

This effort is an update of a previous study performed in 1976 for the U.S. Department of Energy and published by the U.S. Environmental Protection Agency as an Interagency Energy/Environment Research and Development Program Report, Report No. EPA-600/7-78-002. The update was necessitated by the substantial change in economic conditions that have occurred since the initial investigation.

ACKNOWLEDGMENTS

Hoffman-Holt Incorporated has sincerely appreciated the opportunity of working with Mr. William Fedarko of the Office of Coal Utilization and Extraction, U.S. Department of Energy on this interesting and important program. His thoughtful guidance and participation were of utmost importance in producing this report. In addition, all those associated with the program wish to acknowledge the assistance and consultation provided by Messrs. Albert W. Deurbrouck of the U.S. Department of Energy and T. Kelly Janes of the U.S. Environmental Protection Agency as well as the support provided by Ms. Marian McGuire of Hoffman-Holt during the conduct of the program covered by this final report. The authors gratefully acknowledge the assistance and contributions of Mr. Robert W. Spewak in the editing, proofing, formatting and production of this report.

EXECUTIVE SUMMARY

Introduction and Background

The Air Quality Act of 1963 initiated a concerted effort by Federal, state, and local governments for the preservation of the Nation's air quality. This Act called for an expanded Federal research and development program, placing special emphasis on the problem of sulfur oxides emissions from the combustion of fossil fuels in stationary plants.

Coal provides for 20.5 percent (calendar year 1980) of the total fossil fuel energy consumed by all domestic sources (utility, industrial, commercial, and residential). In the utility industry in calendar year 1980, 64 percent of the fossil fuel energy requirement was supplied by coal.

Because pollution from fossil fuel combustion has long been recognized as a problem, major emphasis has been placed on the development of methods for controlling sulfur oxides emissions from fossil-fuel-fired combustors. Current and potentially available methods for controlling sulfur oxides emissions from coal-fired stationary combustion sources fall into the following categories:

- The use of naturally occurring low-sulfur coal;
- The use of low-sulfur coal obtained through physical cleaning;
- Removal of sulfur oxides from the combustion flue gas;
- Capture of sulfur associated components during combustion;

- Chemical treatment to extract sulfur from coal;
- Conversion of coal to clean fuel by such processes as gasification and liquefaction.

Of these methods, for amenable coals, physical removal of pyritic sulfur is the oldest and most developed technology. Another approach to controlling SO_2 emissions could be the combined use of physical cleaning followed by stack gas scrubbing. Such a combined approach could make it possible to utilize moderate to high-sulfur coal with minimal to moderate stack gas scrubbing while continuing to realize the established benefits of coal cleaning such as (1) the availability of a more uniform coal, (2) lower effective transportation costs, (3) reduced electric-utility maintenance costs, and (4) lower coal pulverizing and ash disposal costs.

Sulfur in coal exists in two principal forms, organic and inorganic. The organic sulfur is bound chemically to the coal substance and cannot be physically removed. However, inorganic sulfur (i.e., pyritic) is not bound chemically with the coal substance and may be removed to varying extents by crushing and physical cleaning. The degree of removal is dependent upon pyrite size and distribution, coal size, and other physical characteristics.

Existing cleaning processes, while removing impurities from coal, also reduce the total Btu recovery (i.e., a portion of the heat content of the feed will be lost with the refuse). However, the Btu content per unit weight of the processed product increases owing to removal of low-heat-value impurities. In practice, an

economic balance must be achieved between the Btu loss and the improvement in coal quality. This balance may be further influenced by environmental considerations.

In 1975, the Bureau of Mines sponsored an analytical assessment that would more fully define the potential economics of physical coal desulfurization followed by flue gas desulfurization as a means for increasing the attractiveness of some of our high sulfur coals. The study approach utilized representative parameters. For a number of user situations, assessments were made of the economics of physical cleaning followed by flue gas desulfurization as a means of satisfying environmental-sulfur-related emission standards. Economic parameters were based on the then current and past conditions. Since industry economic factors varied considerably, study values were chosen to provide conservative (i.e., least attractive) economics of physical cleaning followed by flue gas desulfurization. The 1975 assessment indicated the potential attractiveness of coal cleaning combined with flue gas desulfurization (FGD).

In 1980, the Department of Energy decided, that due to the very substantial changes in economic conditions that have occurred since 1975, to sponsor an effort to update the previous study. This effort would also quantify and incorporate in the analyses additional assessment factor(s) that were only identified in the previous report. An overview of the update effort is reported herein.

General Approach

Results from extensive Bureau of Mines and U.S. Department of Energy investigations of coal washability (e.g., float-and-sink tests) shows that the organic sulfur and the effects of crushing vary widely when the washability of coals throughout the U.S. are examined. Some coals can be physically cleaned to a total sulfur-content level consistent with governing environmental standards. In some cases, this can be accomplished at reasonable cost and acceptable loss in total heat-content value (i.e., on a per ton basis). Even though many coals can be cleaned to provide a substantial reduction in total sulfur, the beneficiated coal product is often too high in sulfur to meet environmental requirements. In many cases, the beneficiated coal is close enough to meeting standards that a smaller scale flue gas desulfurization system would enable the coal to be used in an environmentally acceptable fashion at a lower total cost. The required degree of SO_x emission control can often be achieved by employing a flue gas desulfurization system of a low SO_x removal efficiency or a highly efficient flue gas desulfurization system treating only a portion of the total stack gas. This may be particularly applicable in the case of existing power plants which in many states are still permitted to operate at sulfur dioxide emission levels substantially above that required of new facilities.

The overall economics of coal cleaning combined with FGD will be sensitive to the achieved ash and sulfur reductions, the resulting coal yield, and the cost of physical cleaning. The amount of physical desulfurization will relate to the level of sulfur prior to combustion and will therefore help define the required degree of flue gas desulfurization.

Economic Analysis

In order to determine the relative economics of meeting environmental standards via physical coal cleaning combined with partial flue gas desulfurization (FGD) versus full-scale FGD, consideration must be given to the factors influencing the costs and benefits of each approach. For physical coal cleaning, the costs are dependent upon such factors as coal composition and plant size/cost. Offsetting these costs are the benefits of using cleaned coal. The magnitude of these benefits is influenced by the increased heat content of the processed product brought on by the removal of some of the low heat content impurities. In the case of flue gas desulfurization (FGD), costs are influenced by SO_2 concentration and amount of flue gas treated. The considered cost/benefit factors are discussed according to three categories: (1) cost of cleaning coal; (2) benefits of using cleaned coal; and (3) cost of flue gas desulfurization.

Cost of Cleaning Coal

The costs associated with providing a ton of physically cleaned coal at the cleaning plant site (assumed located at the mine) is the sum of the following:

1. The cleaning plant amortization costs associated with each ton of cleaned coal.
2. The cleaning plant operating and maintenance costs associated with each ton of cleaned coal.

3. The cost of raw coal that is utilized in providing one ton of cleaned coal.
4. The share of state and local taxes and insurance on cleaning plant allocated against each ton of cleaned coal.

Benefits of Using Cleaned Coal

The readily identifiable monetary benefits attributable to a power plant burning cleaned coal are as follows:

1. Cleaned coal has a higher heat content per ton than the raw coal from which it is produced. Therefore, less cleaned coal will be required to provide a given heat input to the boiler.
2. Less cleaned coal needs to be shipped to provide a given heat input for a boiler because the heat content per unit weight of coal has been increased through cleaning. Therefore, the cost of shipping (an equivalent amount of energy) will be less.
3. Cleaning reduces the ash content of coal. The amount of ash requiring disposal by the utility will be less due to the lower ash content per ton burned and to the fact that fewer tons of coal will be burned to provide a given heat input.
4. Less cleaned coal needs to be pulverized for a given heat content value, thus reducing the operating and maintenance costs of the pulverizer.
5. There is evidence that savings in power plant maintenance costs will be obtained by using coal with reduced sulfur and ash contents. Since physical cleaning reduces the ash and sulfur contents of coal, lower power plant maintenance cost may result. In addition, for a given heat content value, fewer tons of cleaned coal need to be handled by the power plant. Therefore, power plant equipment, which is tonnage (utilization) limited, will have an increased operational lifetime.

FGD Cost Factors

The cost of FGD increases with the amount of flue gas treated. Significant savings can be realized if the sulfur concentration of the stream can be limited to the point where less than half of the total flue gas needs to be treated by the FGD system to meet standards. This becomes the basic economic concept of combining the two sulfur reduction technologies since such a combined approach could mean the ability to use higher sulfur-content coals with minimal to moderate stack gas scrubbing.

FGD associated costs include:

1. Amortization of capital cost of FGD system;
2. Fuel and electricity cost associated with FGD system;
3. Operating and maintenance costs of FGD system.

Capital and operating costs are dependent on many factors including FGD system size, SO_x concentration of untreated flue gas, SO_x removal efficiency, new or retrofit unit, etc.

Analyses Considerations

The analyses were based in part on:

- A range of selling prices of raw coal and a range of mining costs for a ton of coal.
- Annual stack gas scrubber capital charges that are based on the original investment and the remaining boiler life.

- General power plant locations that are consistent with actual conditions.
- Coal producing areas serving assumed user locations consistent with past patterns.
- Coal transportation parameters consistent with historical patterns and economical coal delivery (to insure conservative economic relationships).
- An assumed power plant boiler size of 500 Mw with an annual utilization of 7000 hours for a new plant and 5000 hours for a 10-year old plant.
- Stack gas scrubber systems of the minimum "practical" sizes necessary to meet standards.

In addition to the many cost and benefit factors that were included as part of this analysis, there were several others which were considered but omitted, owing to either their inability to be reasonably defined and/or quantified at this time, together with their inconsequential impact upon the overall findings of the effort.

Case Studies

A total of forty-eight case analyses were performed. Each case examines one of twelve selected coals and possible use areas from the standpoint of both a new and an existing utility plant using either a combination of physically coal cleaning followed by FGD or sulfur cleanup exclusively by FGD. The cases are grouped according to coal and use area. This permits ease of comparison between similar plants using the same coal in the same area but

utilizing two different approaches to meeting existing or projected environmental emission standards. The emission standards used were those applicable as of January 1981.

Every attempt was made to insure a conservative analysis. The intent was to understate rather than overstate economic benefits. In this regard, attempts were made to employ cost-related factors such as transportation, ash disposal, grinding, cleaning plant utilization, cleaning plant operation and maintenance, etc., that would tend toward conservative economic findings.

To further insure for reasonable comparisons of the cost to meet SO_x emission standards with FGD as compared to combined use of physical coal cleaning followed by FGD, the following guidelines were used.

- (1) The same coal was considered for both cases;
- (2) The amount of flue gas desulfurization considered was only that needed (with small margin) to achieve SO_2 emission standards; and
- (3) Where a range of economic values exist (e.g. coal transportation costs), only those values that would provide conservative savings were used.

The economic assessments indicate that for many potential situations the economic advantage of a combined approach is quite significant. Key elements in economic advantage relate to (1) the availability of coals capable of significant reductions in ash and sulfur at reasonable Btu recovery levels, and (2) a beneficiated-coal sulfur level that is compatible with significantly less than full-scale scrubbing requirements. Even so, the range of variables is such that each source-user combination must be individually

assessed. In this regard, it should be noted, the results can be weighted unrealistically to indicate excessively attractive economics by employing unrealistic factors (e.g., using shipping costs higher than warranted).

The cost assessments of FGD combined with coal cleaning as compared to FGD used alone indicated savings as high as 70 percent to an additional 3 percent cost as compared to flue gas desulfurization alone when applied to new steam coal utilities. The results are even more impressive for existing plants, where study assessments indicated a 15 percent to 91 percent savings for physical cleaning followed by FGD as compared with FGD alone.

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1.0 INTRODUCTION

The Air Quality Act of 1963 initiated a concerted effort by Federal, State, and local governments for the preservation of the Nation's air quality. This Act called for an expanded Federal research and development program, placing special emphasis on the problem of sulfur oxides emissions from the combustion of fossil fuels in stationary plants.

Coal provides for 20.5 percent (calendar year 1980) of the total fossil fuel energy consumed by all domestic sources (utility, industrial, commercial, and residential). In the utility industry in calendar year 1980, 64 percent of the fossil fuel energy requirement was supplied by coal (Reference 1).

At times during the last 10 years, electric power generation had increased between 5 to 8 percent per year. More recently, the yearly increase has been much more moderate (Reference 1). This increasing demand for electrical energy, the continuing escalating cost of fuel oil with the uncertainty of the foreign supply, the uncertainty in the availability and price of natural gas, and the delays in constructing and licensing nuclear power plants have resulted in a continuing increase in the use of coal as a major source of energy in the utility industry. Coal consumption by domestic utilities was 569 million tons in 1980 (Reference 1), may be as high as 880 million tons by 1990, and could be over 1300 million tons in the year 2000.

Because pollution from fuel combustion has long been recognized as a problem, major emphasis has been placed on the develop-

ment of methods for controlling sulfur oxides emissions from fossil-fuel-fired combustors. Current and potentially available methods for controlling sulfur oxides emissions from coal-fired stationary combustion sources fall into the following categories:

- The use of naturally occurring low-sulfur coal;
- The use of low-sulfur coal obtained through physical cleaning;
- Removal of sulfur oxides from the combustion flue gas;
- Capture of sulfur associated components during combustion;
- Chemical treatment to extract sulfur from coal;
- Conversion of coal to clean fuel by such processes as gasification and liquefaction.

Of these methods, for amenable coals, physical removal of pyritic sulfur is the oldest and the most developed technology. Another approach to controlling SO_2 emissions could be the combined use of physical cleaning followed by stack gas scrubbing. Such a combined approach could make it possible to utilize moderate to high-sulfur coal with minimal to moderate stack gas scrubbing while continuing to realize the established benefits of coal cleaning such as (1) the availability of a more uniform coal, (2) lower effective transportation costs, (3) reduced electric-utility maintenance costs, and (4) lower coal pulverizing and ash disposal costs.

Coal is a heterogeneous material containing combustible matter and mineral matter. The mineral matter or impurities may be broadly divided into two categories--those that form ash, and those that contribute sulfur. The ash-forming and the sulfur-containing

impurities can be further subdivided into two classes: (1) Impurities that are structurally a part of the coal and cannot be removed by physical means, and (2) impurities that can be liberated by crushing and removed by physical means.

Sulfur in coal exists in two principal forms, organic and inorganic. The organic sulfur is bound chemically to the coal substance and cannot be physically removed. However, inorganic sulfur (i.e., pyritic) is not bound chemically with the coal substance and may be removed to varying extents by crushing and physical cleaning. The degree of removal is dependent upon pyrite size and distribution, coal size, and other physical characteristics.

Physical cleaning of coal has been used for many years. Its principal purpose has been to reduce the so-called ash-forming impurities. If any of the impurities are pyrites it would also reduce the total sulfur in the coal. The process in common use for reducing such impurities is a combination of stage crushing and specific gravity separation. Shale and coal having different specific gravities may be separated. Froth flotation, dependent on differences in surface characteristics of coal and refuse, is used for removing impurities from very fine size coal.

Existing cleaning processes, while removing impurities from coal, also reduce the total Btu recovery (i.e., a portion of the heat content of the feed will be lost with the refuse). However, the Btu content per unit weight of the processed product increases owing to removal of low-heat-value impurities. In practice, an

economic balance must be achieved between the Btu loss and the improvement in coal quality. This balance may be further influenced by environmental considerations.

In 1965, EPA sponsored a study to quantify the impact that coal cleaning, optimized for pyrite removal, could have on the control of sulfur oxides emissions. This study found that it was impossible to quantify the impact of coal cleaning on sulfur oxides emissions because of large gaps in available information. The study identified the following areas where required information was either not available or was inadequate for appraising this impact:

- Knowledge of the distribution of sulfur forms in all major utility-coal-producing coalbeds in the United States;
- Effectiveness of available commercial coal preparation methods for pyrite separation, together with the development or modification of these techniques to maximize sulfur reduction;
- Identification and assessment of processes that could economically utilize coal cleaning reject material for byproduct recovery, thereby aiding the overall cleaning economics and reducing potential air, water, and solid pollution.

The findings of the 1965 study led EPA to proceed with implementation of a comprehensive program designed to define the role of coal cleaning in controlling sulfur oxides emissions from coal-fired sources. A major portion of this effort was initially performed by the U.S. Bureau of Mines and subsequently by the same office upon transfer to DOE. An important objective of the program was to determine the extent to which the sulfur content of the U.S. coals could be reduced by coal cleaning processes based on

differences in physical properties. While pyritic sulfur is amenable to removal by such processes, the other major form of sulfur (organic sulfur compounds) is not. A good indicator of the "cleanability" of pyrites from a coal is the specific gravity analysis, or float-and-sink test, in which the crushed coal is tested at various gravities to effect a separation between coal and impurities. Such float-and-sink tests formed an important element of the total program by providing the basic data for determining the amount of sulfur removal that can be achieved.

Increased interest in the utilization of coal, together with the realization that substantial quantities of U.S. coals exhibit reasonable sulfur reductions on physical cleaning, has led to consideration of coal preparation as a total or partial step in meeting environmental standards. One approach would be to physically clean those coals that show significant sulfur reductions at reasonable cost, and then use a minimal, economically attractive, flue gas desulfurization system.

In 1975, the Bureau of Mines sponsored an analytical assessment that would more fully define the potential economics of physical coal desulfurization followed by flue gas desulfurization as a means for increasing the attractiveness of some of our high sulfur coals. The study approach utilized representative parameters. For a number of user situations, assessments were made of the economics of physical cleaning followed by flue gas desulfurization as a means of satisfying environmental-sulfur-related emission standards. Economic parameters were based on the then current and past conditions. Since industry economic factors varied considerably, study values were chosen to provide conserva-

tive (i.e., least attractive) economics of physical cleaning followed by flue gas desulfurization. The report of this effort (Reference 2) was well received.

In 1980, the Department of Energy decided, that due to the very substantial changes in economic conditions that have occurred since 1975, to sponsor an effort to update the Reference 2 assessment. This effort would also quantify and incorporate in the analyses additional assessment factor(s) that were only identified in the previous report.

2.0 GENERAL CONSIDERATIONS & APPROACH

2.1 General Considerations

In the initial study, reasonable coal-source and user combinations were established, and analyses were conducted to determine whether there was any potential economic advantage associated with physical cleaning followed by flue gas desulfurization (FGD) over FGD alone to meet environmental standards. The initial study (Reference 2) indicated that physical coal cleaning combined with flue gas desulfurization often could provide significant economic advantage. Significant economic changes have occurred since the initial study. In addition, the standards of performance (including allowable SO_2 emissions) for electric utility generating units with heat input of more than 250 million Btu per hour (of fossil fuel) for which construction commenced after September 18, 1978 has been made more restrictive. The new SO_2 emission standard calls for a percentage reduction over the uncontrolled emission value as well as a maximum SO_2 (i.e., per million Btu) emission value. The required percentage SO_2 emission reduction over the uncontrolled level is dependent on the coal Btu and sulfur values. It should be noted that new units commencing construction after September 18, 1978 will not come on stream until probably the late 1980's. The Federal (i.e., not the state) limitation for plants covered by the previous performance standard continues to be 1.2 pounds of SO_2 per million Btu heat input.

As indicated, this study is an update of the previous (Reference 2) study. The current effort reassessed all identified cost/benefit items and relationships. An intent of the update

effort is to provide a general methodology whereby a given utility can utilize its unique facility related conditions and associated economic parameters in assessing the economics of coal cleaning combined with FGD in achieving the required SO₂ emission limitation.

The current study, in effect, provides a snap-shot in time illustration, using January 1981 as the base point, for comparing a fully operational utility employing FGD with unbeneficiated coal against the same utility using FGD and beneficiated coal. To be fully operable by that date, many activities (e.g., construction of coal cleaning plant) would have to be started long before January 1981. Financing and design of the construction would, of course, have had to precede the construction activity. To demonstrate the application of the methodology, a number of representative case studies have been developed. Summaries of these case studies are provided in Section 6.4; the full case studies are presented in Appendix A.

2.1.1 Selection of Coal Source Areas

To determine the coal source side of these combinations, it was necessary to identify coal source areas possessing coals that display apparently attractive cleaning potential. Such coals are found in the Northern Appalachian and Eastern Interior Regions.

2.1.2 Selection of Coal Use Areas

Having established general coal source areas, states were identified that have historically been served by these areas. From these, 20 states were selected which have emission regulations in a range compatible with the burning of moderate (1 to 3 percent) and low-sulfur (less than 1 percent sulfur) content coals. The considered states were: Alabama, Delaware, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. Within each of these states, a number of current or past coal-burning utility locations were identified from which a total of 12 were selected for the case study applications. Then, 12 specific coals from the Northern Appalachian and Eastern Interior Regions were individually matched with these 12 selected coal-burning locations. Each coal-source/coal-use-area pair was based on a known past source-area/use-area relationship.

2.2 General Approach

For certain coal user areas, some coals can be physically cleaned to a total sulfur content level consistent with governing environmental standards. In some cases this can be accomplished at reasonable cost and reasonable loss in total heat content value (i.e., on a per-ton basis). Even though many coals can be cleaned to provide a substantial reduction in total sulfur, the beneficiated coal product is often too high in sulfur to meet environmental requirements. In many cases, the beneficiated coal is not too far from meeting standards and a small amount of SO₂ emission

control would enable the coal to be used in an environmentally acceptable fashion. The required degree of SO_2 emission control can often be achieved by employing either a low removal efficiency SO_x flue gas desulfurization system or a highly efficient flue gas desulfurization system treating only a portion of the total stack gas.

This effort specifically addresses the applicability and the economics of physical desulfurization followed by flue gas desulfurization as a means for keeping our higher sulfur coals in the energy market. The advantage of such an approach would necessarily relate to economics (i.e., cost compared to other options for sulfur oxides emission control).

The relationship between flue gas desulfurization cleaning efficiency, portion of the total gas cleaned, and normalized emission level is defined by the following:

$y = 1 - nx$
where y = total SO_2 emitted with FGD/total SO_2 emitted without FGD,
 n = flue gas desulfurization efficiency of treated portion of flue gas (expressed as a decimal),
and x = decimal proportion of flue gas cleaned.

Therefore, for a given cleaning efficiency, the relationship between portion of gas cleaned and the normalized emitted SO_2 emission level (i.e., y) is defined by a straight line. In a

similar manner, the relationship between portion of gas cleaned and the normalized amount removed is also described by a straight line.

For a flue gas desulfurization system with a 90 percent removal efficiency we have--

<u>Percent of Gas Cleaned</u>	<u>SO₂ Emitted (normalized value)</u>	<u>SO₂ Removal (normalized value)</u>
0	1	0
10	0.91	0.09
20	0.82	0.18
30	0.73	0.27
40	0.64	0.36
50	0.55	0.45
60	0.46	0.54
70	0.37	0.63
80	0.28	0.72
90	0.19	0.81
100.	0.10	0.90

For a flue gas desulfurization system with an 85 percent removal efficiency we have--

<u>Percent of Gas Cleaned</u>	<u>SO₂ Emitted (normalized value)</u>	<u>SO₂ Removal (normalized value)</u>
0	1	0
10	0.92	0.08
20	0.83	0.17
30	0.75	0.25
40	0.66	0.34
50	0.58	0.42
60	0.49	0.51
70	0.41	0.59
80	0.32	0.68
90	0.24	0.76
100	0.15	0.85

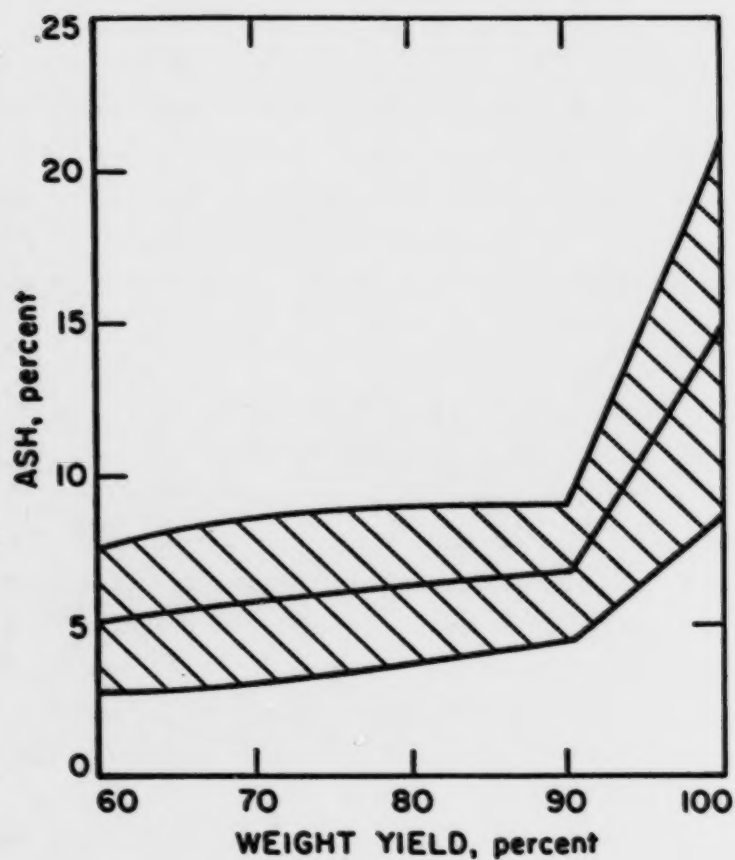
For a flue gas desulfurization system with an 80 percent removal efficiency we have--

<u>Percent of Gas Cleaned</u>	<u>SO₂ Emitted (normalized value)</u>	<u>SO₂ Removal (normalized value)</u>
0	1	0
10	0.92	0.08
20	0.84	0.16
30	0.76	0.24
40	0.68	0.32
50	0.60	0.40
60	0.52	0.48
70	0.44	0.56
80	0.36	0.64
90	0.28	0.72
100	0.20	0.80

Given the ash, Btu, and sulfur contents of a raw coal, related float-sink test data, transportation economics, and SO₂ emission limitations, economic assessments of coal cleaning (to remove sulfur and ash) followed by SO₂ cleanup can be addressed. These assessments would cover the various identified costs and benefits directly related to coal beneficiation. These benefits (other than those associated with environmental satisfaction) mainly result from lower coal ash and sulfur content via cleaning. The cleaning costs and benefit assessments can then be modified to encompass the SO₂ cleanup process.

The overall economics will be sensitive to the achieved ash and sulfur reductions, the resulting coal yield, and the cost of physical cleaning. The obtained sulfur reduction on physical cleaning will effectively define the level of sulfur prior to combustion and will therefore define the required degree of flue gas desulfurization to meet a specific standard. In this regard, it should be noted that in general for a given top size, coal exhibits a reasonably sharp break point in attainable sulfur and ash reduction as a function of yield. If coal beneficiation combined with FGD has any attractiveness for a given use situation, the optimum coal beneficiation level would be somewhere in the region where a sharp change in ash and sulfur reduction potential versus yield occurs.

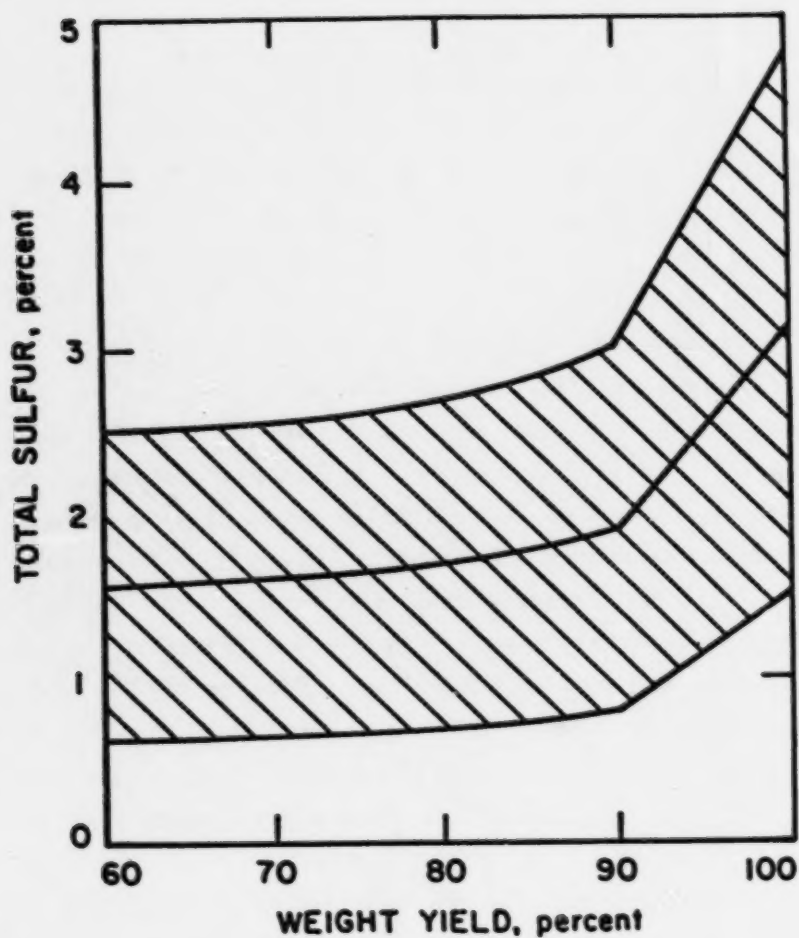
In general, for most of the coals examined, this break point usually occurs in the vicinity of a 90 percent weight yield. This general condition (for 3/8-inch top size coal) is indicated for Northern Appalachian coals by Figures 1 and 2 (Reference 3). For



Source: United States Bureau of Mines RI 7633,
1972 (page 234).

Figure 1

Average ash content, ± 1 standard deviation at 3/8
inch top size, Northern Appalachian region coals.



Source: United States Bureau of Mines RI 7633, 1972
(page 235).

Figure 2
Average total sulfur content, ± 1 standard deviation
at 3/8 inch top size, Northern Appalachian region coals.

this effort, the yield value chosen for a given assessment is based on the sulfur reduction breakpoint (i.e., 45° slope) as indicated by float-sink test data.

It should be noted that the sharp break indicated on Figures 1 and 2 is exaggerated owing to the fact that the 90 percent point was the first data point. Even so, the maximum change in sulfur and ash reduction potential versus yield generally occurs for coals of interest in the neighborhood of a 90 percent yield.

Currently, in the majority of utility applications, electrostatic precipitators are used with or without an FGD system. Therefore, precipitator-related economics are not considered in this study. Early FGD systems combined particulate and SO₂ removal in the same scrubber to realize potential cost savings. However, there are a number of problems associated with this combined approach. For example, the fan can no longer be operated dry, which creates corrosion and imbalance potential. Another area of difficulty is the fact that the chemistry of the SO₂ system is affected by the addition of the particulate in the slurry. Further, the SO₂ system cannot be bypassed without also bypassing the precipitator, thus losing the entire particulate removal function. Finally, if the fly ash is collected dry and then mixed with the sludge, there is a higher percent total solids content than if the fly ash is wetted along with the sulfate sludge. As a result of these numerous considerations, this study addresses installations using precipitators followed by dry fans and then followed by SO₂ scrubbers.

2.3 Excluded Factors

In addition to the many cost and benefit factors that were included as part of this study, there were several others which were considered but omitted owing principally to their inconsequential impact upon the overall findings of the effort. The net effect of these omissions has been to understate the potential economic benefits of physical coal cleaning coupled with subsequent FGD. The following is a brief summary of those factors:

- Crushing and Screening Cost Savings - When raw coal is not going to be physically cleaned, it is normal practice in the coal industry to crush and screen to a topsize of 2 inches that coal which is to be sold to utility plants. The overall cost of this process including coal loading has been estimated by industry personnel to be as high as \$1.00 per ton. When coal is physically cleaned, it is not necessary to perform the crushing and screening separately since these functions are now integrated with the overall cleaning process. For purposes of this study, coal cleaning costs were not reduced by the cost of crushing and screening even though there is a definite savings to the mine operator by not having to perform these separately. If these savings had been considered a benefit by the study, the net cost of physical cleaning would have been reduced, and thus the relative economics of using physically cleaned coal followed by FGD as compared to FGD alone would have been improved.
- Reduction in FGD Installation Time - By using physically cleaned coal, less of the flue gas needs to be processed by the FGD system and therefore fewer or smaller FGD units are required to meet environmental standards. This has not only the benefit (as covered by the study) of reducing the FGD cost, but it also reduces the construction time. Additionally, the total sludge disposal at the plant site is reduced significantly from what it would be in the absence of coal cleaning.

This will, in some cases, reduce the time required for, and the difficulty with, obtaining legal permits and site acquisition for ponding and/or landfill.

- Less Derating of Power Plant Output - FGD systems require power to operate. The smaller FGD systems that could result from using physically desulfurized coal would require less operating power. This would result in more marketable power for the same power plant fuel input level.
- Greater Boiler Efficiency - Cleaning reduces the coal ash content. This results in a lower boiler ash per million Btu of coal burned. As a consequence, less sensible heat is lost with the ash for a given boiler Btu input, thereby providing for a slight increase in boiler efficiency.
- Possible Creation of a Market or the Establishment of a Long-Term Sales Contract - In many cases the physical cleaning of coal could create markets for coal which are relatively unattractive in their raw form. The providing of beneficiated coals compatible with particular use situations could lead to the creation of long-term sales contracts matching specific cleaned coals with specific users. This arrangement works to the advantage of all concerned by giving the mine operator a long-term source for his product and the utility a predicatably uniform product over an extended period which has been efficiently matched to operating requirements. It would also be beneficial from a national point of view because it would increase the country's long-run supply of usable domestic energy.

3.0 EVALUATION OF COSTS ASSOCIATED WITH THE COAL CLEANING PROCESS

Physical cleaning involves the removal of waste products such as shale, pyrite, and roof slate from coal by utilizing differences in the physical properties of the materials. The practice of physically cleaning coal has existed for many years; however, until the relatively recent concern with SO_2 emission, the purpose has been to remove the so-called ash-forming impurities. This material is removed to reduce transportation charges and the operating problems and associated expenses that this ash-forming material causes in practically all major uses of coal. About 34 percent of the bituminous coal and lignite produced in 1978 was mechanically (i.e., physically) cleaned (Reference 4). Cleaning equipment includes a variety of jigs, tables, launders, dense-medium and flotation washers, and pneumatic devices, all of which depend upon the difference in specific gravity and froth flotation that depends upon the surface chemistry of fine coal. The specific cleaning method chosen depends on the size of coal to be upgraded, the composition of the raw product, and the chemical-quality specifications imposed by the consumer.

Sulfur is found in raw coal in two major forms: organic and inorganic (pyritic sulfur). The organic sulfur is considered an inherent constituent of the coal and cannot be reduced by use of conventional cleaning methods. The pyritic sulfur occurs in particles of varying size mixed with the coal. By crushing (to liberate the pyritic sulfur) and cleaning (to remove the liberated particles), the total amount of sulfur in the coal may be reduced. The degree of removal of the pyritic sulfur is dependent on the size of the particles of pyrites; the finer the particles, the more

difficult to remove by cleaning. The total sulfur reduction, therefore, is dependent on the amount of organic sulfur and the effects of crushing to liberate the pyritic sulfur. The desulfurization process results (as do most beneficiation processes) in some loss in total heat content of the processed coal.

To obtain a low sulfur level (less than 1 percent total sulfur) in the physically cleaned coal requires that the organic sulfur content in the raw coal be less than 1 percent. A summary of washability tests by the Pittsburgh Mining Research Center, DOE (formerly the U.S. Bureau of Mines) shows that the organic sulfur and the effects of crushing and cleaning vary widely, as would be expected, when washability data of coals throughout the United States are considered (Reference 5).

3.1 Cleaning Cost Factors

The cost associated with providing a given amount of physically cleaned coal at the cleaning plant site (assumed located at mine) is the sum of the following:

- The cleaning plant amortization costs associated with the cleaned coal.
- The cleaning plant operating and maintenance costs associated with the cleaned coal. Operating costs also include the disposal of the refuse associated with the cleaning operations.

- The value of raw coal that is utilized in providing the cleaned coal.
- The share of State and local taxes and insurance (on cleaning plant) allocated against the cleaned coal.

3.2 Cleaning Plant Amortization Costs

Mechanical cleaning of coal is possible because of the differences between the physical properties of coal and those of its impurities. For the cleaning process to provide attractive pyrite removal benefits, it is necessary to select coals which possess characteristics amenable to pyrite removal and to have an appropriately designed cleaning plant.

The cost of a coal cleaning plant can vary over a wide range. Plant cost basically depends on plant capacity, equipment composition, and top size of prepared coal, assuming no undue site preparation charges. In general, for a given cleaning plant capacity, the smaller the coal particles, the greater the cleaning plant costs. The increase in plant costs required to clean fine coal is due to both the greater capital equipment cost for cleaning the finer coal and the higher operating and maintenance cost associated with fines dewatering, especially if thermal drying has to be used.

3.2.1 Data Considerations

Even though some cost data on a number of existing coal preparation plants are available, such data must be used with caution for a number of reasons, including the following:

- Existing plants may not be representative of required coal cleaning plant(s).
- The age of many existing plants is not well defined.
- The questionable ability to extrapolate or project current plant costs from plants of different total makeup that were constructed in past years under different economic conditions.
- The intricate details of existing plants are not well known (effectiveness and utilization restrictions).
- Variabilities resulting from owner economic philosophy, unique cleaning plant site conditions, site specific environmental concerns, etc.

These factors must be considered when using past plant-cost data to judge the reasonableness of newly acquired plant-cost estimates.

3.2.2 Capital Equipment Costs

The characteristics of the raw coal to be upgraded have to be carefully investigated together with a determination of the finished product before an estimate of cleaning plant configuration and cost can be made. In general, the finer the coal is crushed, the more the impurities are liberated. However, as coal size is reduced and finer coal is cleaned, the complexity of the cleaning plant increases along with increased capital cost.

There is a limit as to the minimum coal topsize that would be practical for utility usage. An overly small topsize can result in many problems. These include:

- Fine coal is difficult to handle and ship and contributes to additional undesirable transit loss,
- Fine coal is difficult to store and is subject to greater wind loss,
- Fine coal picks up and holds more moisture, and
- Fine coal leads to utility plant conveying and pulverizer difficulties.

Therefore, this effort considers a "reasonable" minimum coal topsize of 3/8 inch out of a cleaning plant. If finer coal were obtained, reagglomeration would probably be necessary. This is outside the scope of this effort. Even so, it should be noted that very fine coal is used for a coal/water slurry fuel.

There are four general alternatives that are considered regarding processing of raw coal, as follows:

- No Cleaning - Steam coals are often utilized without cleaning. Currently, as in the past, cleaning is principally employed to upgrade coal by removing impurities such as clay, rock, shale, and pyrite. Even so, depending on overall cleaning and transportation economics (e.g., cost of transporting noncombustibles) and other coal quality/user considerations, coal is often sold without benefit of cleaning.

- Partial Washing (Coarse-Size Coal Plant) - In a coarse-size coal plant only the larger size fractions of coal are treated. Typically, a given coal could contain 50 to 60 percent plus 3/8-inch coal with the fines reasonably low in ash and sulfur. The plus 3/8-inch portion of the feed is washed and mechanically dried to a low moisture content. The separated and untreated minus 3/8-inch portion of the feed is combined with the cleaned coarse coal for shipment.
- Coarse Washing with Partial Washing of Fines (Coarse-Size and Fine-Size Coal Plant) - In this case all the feed is wetted, but only the plus 48-mesh fraction is washed; the minus 48-mesh material is frequently discarded. All the utilized coal would be mechanically dried. This approach often results in the exclusion of the minus 48-mesh material (the most difficult and expensive to dewater) from the product. This process generally results in a lower yield and often results in higher cost and problems associated with disposal of the tailings.
- Total Washing - In this case all the feed is wetted and washed. The cost of the plant will vary depending on the top size of coal treated. Such a plant could consist of both coarse (e.g., plus 3/8-inch coal) and fine (e.g., minus 3/8-inch coal) circuits or could be composed entirely of fine coal circuits.

A plant designed to crush run-of-mine (ROM) coal to 3- to 5-inch top size resulting in 50 to 60 percent plus 3/8-inch (coarse) coal would wash the coarse coal, followed by dewatering to remove the surface moisture. The fines (e.g., minus 3/8-inch coal) would be wet-washed, followed by mechanical dewatering and possibly heat drying. A plant optimized to remove pyritic sulfur and ash from amenable coals would in many instances be a total fine coal plant. Such a plant would crush ROM coal to 3/8-inch top size prior to processing. Plants of this type would include tables and/or cyclones, froth flotation units, filters, sizing and dewatering screens, mechanical and/or thermal dryers, and water clarification provisions.

For this study, cleaning plant capital costs were obtained from knowledgeable and technical and management staff of engineering companies engaged in the design and construction of coal cleaning plants. Initially, in mid-1976, companies were contacted and cost information requested. Specifically, turnkey cleaning plant cost and plant makeup for 3/8-inch (or 1/2-inch) topsize (fine coal) and 1-1/2 inch topsize processing of Northern Appalachian and Midwest steam coals were requested. The requested cost and design information were for coal processing plants that would provide the capability for removing pyritic sulfur from the more readily cleanable coals. Information obtained from several designers and constructors of coal processing plants indicated that for either Northern Appalachian or Eastern Interior steam coals a fine coal preparation plant would cost \$16,000 to \$18,000 per ton per hour of input capacity for plants with capacities of 500 or more tons per hour. A similar capacity plant for processing 1-1/2 inch coals from the same geographic regions would cost from \$14,000 to \$16,000 per ton per hour input capacity. As previously indicated, the information was supplied by personnel well aware of the plant capabilities that would be required to beneficiate coals of interest. Such plants could include tables and/or cyclones, froth flotation units, filters, a range of screen sizes, and mechanical and thermal dryers. The design would provide for drying of fines and would remove the surface moisture from the larger fraction to aid shipping. In addition, included provisions would provide a slurry pond for the fine refuse and a pit for the coarse refuse.

In January 1981, updated cost information was sought from the same engineering companies. Received information was that the current cost for a similar fine coal plant has escalated to between

\$23,000 and \$27,000 per ton per hour input capacity. The current cost for a 1-1/2 inch plant would be between \$20,000 and \$23,000 per ton per hour input capacity. Furthermore, over the last several years, the escalation in plant cost has averaged 12% per year.

Cost indexes covering equipment related to coal beneficiation are reported by the U.S. Department of Labor, Bureau of Labor Statistics. Table 1 provides index ratios from 1976 through the latest available values for reported equipment associated with coal cleaning. The ratio of the prices between any two periods is simply the ratio of the index values, the decimal increase being the ratio value minus 1.

3.2.3 Capital Equipment Amortization

There are a number of ways that a company may choose to address the financing and the resulting amortization burden associated with acquiring a coal beneficiation (i.e., cleaning) plant. A levelized payment schedule over the amortizable life of the beneficiation plant would be appropriate for analysis purposes. One way this can be accomplished is by assuming that the plant would be financed by the economic equivalent of a loan covering the total plant with amortization by means of an equal-payment, self-liquidating loan. This approach can be utilized for analysis purposes even though some other financing concept is actually employed. In practice, parameters must be used that are appropriate to the current financial situation.

TABLE 1

BUREAU OF LABOR STATISTICS COST INDEXES FOR
EQUIPMENT ASSOCIATED WITH COAL BENEFICIATION
(Base 1967 = 100)

<u>Category</u>	<u>1976</u> <u>Avg.</u>	<u>1977</u> <u>Avg.</u>	<u>1978</u> <u>Avg.</u>	<u>1979</u> <u>Avg.</u>	<u>1980</u> <u>Avg.</u>	<u>Dec.</u> <u>1980</u>
Crushing, pulverizing, screening, machinery	197.8	213.8	229.2	252.7	279.4	293.0
Classifier	305.2	NA	323.8	337.3	377.7	413.0
Flotation machine	200.8	209.5	230.4	247.3	285.2	311.7
Roll crusher	217.8	236.4	263.0	294.0	NA	NA
Vibrating screen	115.9	127.0	131.9	143.0	156.5	165.7
Gyrator crusher	179.4	190.7	207.2	232.3	261.2	267.3
Mining machinery and equipment	212.0	228.6	249.7	272.9	306.9	320.6

NA - Not Available

Therefore, it is assumed that regardless of tax and depreciation considerations, a mine operator would finance and amortize a coal preparation plant by means of an equal-payment, self-liquidating loan or its equivalent. Information from designers and constructors of coal preparation plants indicates that the interest rate for a loan for financing a coal cleaning plant would at best be 2 to 3 points above the prime interest rate. The more financially sound borrowers, of course, would obtain the more attractive rates. If the loan is payable with equal installments, the amount due per period per dollar of loan as a function of the loan period and the interest rate is given by--

$$R = \frac{i (1 + i)^n}{(1 + i)^n - 1}$$

where

R = capital recovery per period per dollar invested,

i = interest rate per period expressed as a decimal,

and

n = number of periods in the amortization schedule.

Therefore, the factor R multiplied by the amortizable cost yields the per-period fixed cost covering interest and principal.

Industrial-quality coal cleaning plants, when properly maintained, will undoubtedly have a life expectancy of greater than 20 years. Even so, the writeoff or amortization period is usually based strictly on company fiscal policy as constrained or guided by Internal Revenue Service policies and regulations. Reference 6

contains IRS guidelines for depreciable assets used by business in general. Under the category of Mining, defined to include the mining and quarrying of metallic and nonmetallic materials plus the milling, beneficiation, and other preparation of such materials, Reference 6 indicates an 8- to 10-year depreciation period. Even so, discussions with industry indicated that even though a coal cleaning plant can be written off in about 10 years, prudent considerations often dictate a writeoff period of 15 years. A 15-year depreciation period, therefore, was used for the provided case study applications.

For a 15-year depreciation period, the monthly installment per dollar of loan value equals:

$$R = \frac{i (1 + i)^{180}}{(1 + i)^{180} - 1}$$

where i = monthly interest rate expressed as a decimal.

It is assumed that a loan negotiated for plant financing would bear an interest value that is two points in excess of the prime commercial rate. This would be the rate at the time of financing prior to construction. Therefore, we have--

When Prime Interest	i Per Month	R Per Year
Rate Equals	Becomes	Equals
8%	$(0.08 + 0.02)/12 = 0.00833$	0.12895
10%	$(0.10 + 0.02)/12 = 0.01$	0.14402
12%	$(0.12 + 0.02)/12 = 0.011666$	0.15981
14%	$(0.14 + 0.02)/12 = 0.013333$	0.17624
16%	$(0.16 + 0.02)/12 = 0.015$	0.19325
18%	$(0.18 + 0.02)/12 = 0.016667$	0.21076
20%	$(0.20 + 0.02)/12 = 0.018333$	0.22869
22%	$(0.22 + 0.02)/12 = 0.02$	0.24699
24%	$(0.24 + 0.02)/12 = 0.021667$	0.26561

The yearly amortization costs for various amortization periods and interest rates (on the unpaid balance) are provided in terms of plant cost per ton per hour input capacity. The share of amortization costs attributable against each plant input ton of coal is merely the per ton per hour input capacity yearly amortization cost divided by the yearly operating hours. The amortization cost per ton of cleaned coal is simply the cost per plant input ton divided by the recovery (i.e., yield) expressed as a decimal.

The yearly operating hours of a cleaning plant as a function of plant utilization are indicated in Figure 3. For the purposes of this study a plant utilization factor of 38.58 percent was used. This is based upon the cleaning plant operating 260 days per year, 13 hours per day. Although this represents typical industry practice, greater plant utilization would mean reduced capital amortization contribution per ton of cleaned coal and thus improve the economics associated with physical cleaning.

An example of per-ton cleaned coal amortization values is given in Figure 4. These values are provided for a range of plant yields and utilization factors and are based on--

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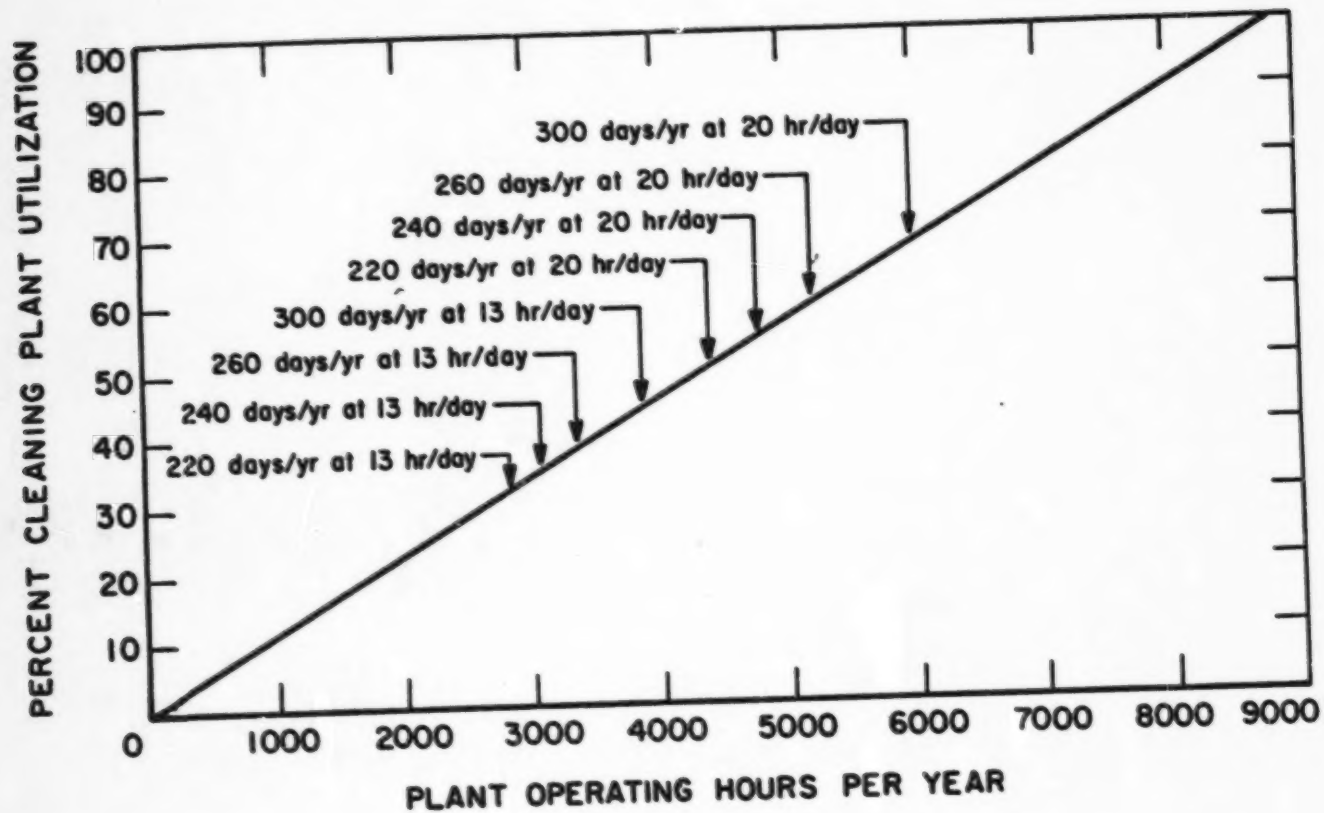


Figure 3
Cleaning plant utilization

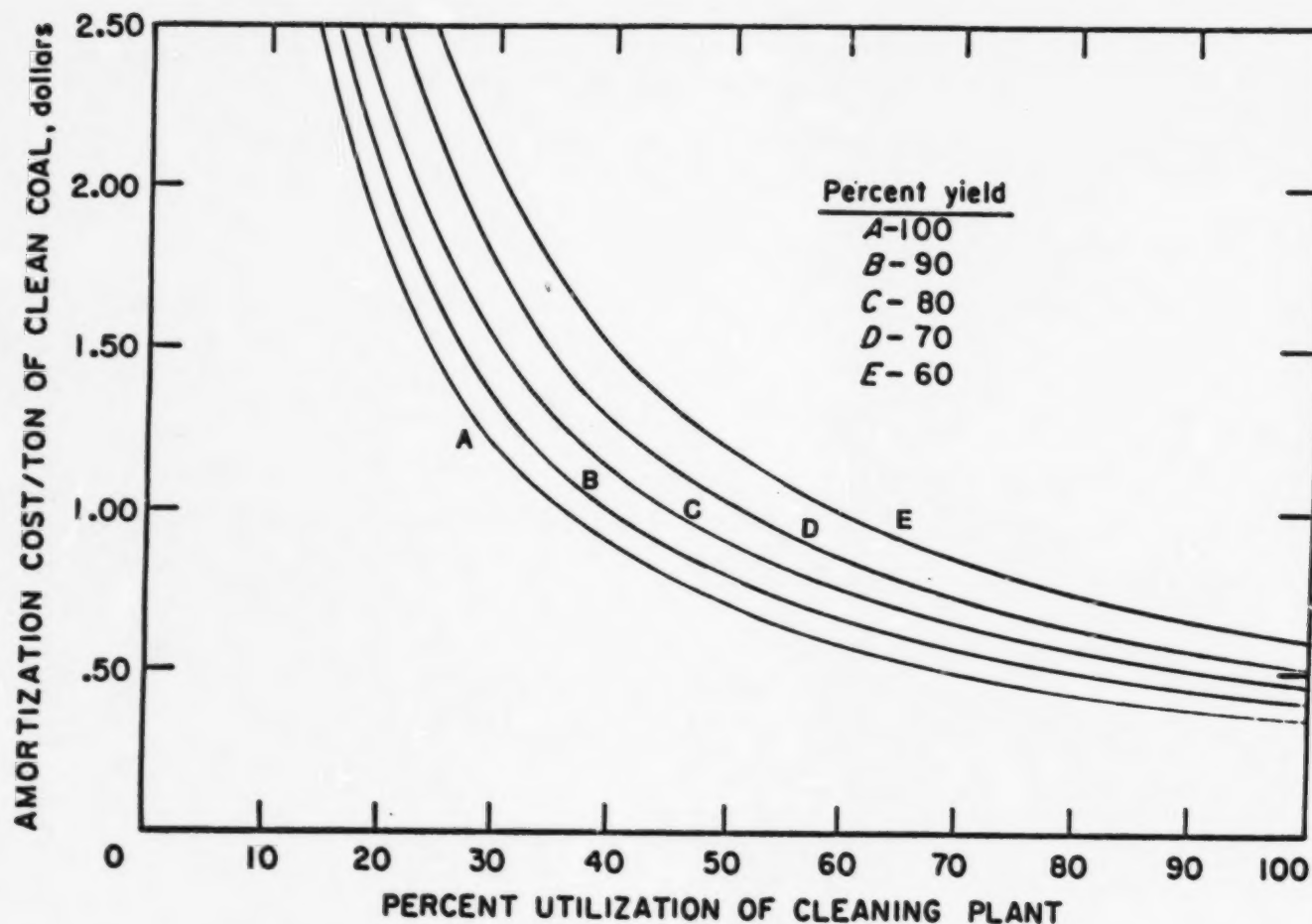


Figure 4

Amortization cost/ton cleaned coal for:
 plant cost - \$20,000 per ton-hour input capacity,
 interest rate - 13.75%, loan period 15 years.

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- A plant costing \$20,000 per ton per hour input capacity at initiation of construction in January 1979.
- A 15-year amortization period
- A 13.75 percent interest (on unpaid balance)

In the provided case analyses, the utilized amortization values are based on factors consistent with assumed case conditions.

3.3 Cleaning Plant Operation and Maintenance Costs

Operation and maintenance (O&M) costs are a function of--

- Coal yield (i.e., weight percent of plant input coal that becomes clean coal)
- Cleaning plant labor requirements and rates
- Maintenance costs
- Cost of operating supplies
- Power costs
- Refuse handling and disposal costs

For a given plant, the throughput time required to produce a ton of "clean" coal depends on yield (i.e., the percentage of raw coal that ends up as cleaned coal). As an example, if a cleaning plant operating at input capacity takes X hours with a given yield to process or provide 1 ton of clean coal, then the same plant when

operating at half the previous yield will take essentially 2X hours to provide 1 ton of clean coal. Therefore, the cleaning plant operating costs attributable to 1 ton of cleaned coal are (essentially) inversely proportional to cleaning plant yield. In like manner, maintenance, supply, and power costs will also be inversely proportional to yield. Refuse handling and disposal costs, which are relatively minor on a high yield plant, do not follow this same relationship. This is evident from the fact that for 100 percent yield, refuse will not exist, and therefore refuse costs will be zero.

3.3.1 Operation & Maintenance Cost Data Considerations

Cleaning plant operation and maintenance (O&M) costs were derived from a recently DOE sponsored study (Reference 7) on coal plant operation and cost. Data contained in this report were used in deriving the estimated O&M costs as a function of cleaning plant (weight) yield. The derived cleaning plant O&M cost versus cleaning plant yield relationship is used in the case studies included in this report.

The Reference 7 study contains coal preparation plant cost data, as of December 1977, on eight currently operating coal preparation plants. Three and possibly four of the eight plants are of the general complexity that would be required to reasonably beneficiate those coals that indicate attractive sulfur reduction potentials. Operation and maintenance data from these four plants were used in developing the provided estimates of cleaning plant O&M costs as a function of plant yield. The mean of the examined plants O&M costs was used for this effort. The mean of the December 1977 costs was modified in accordance with the Bureau of Labor Statistics coal mining industry cost indices in order to provide economic values for the time period of interest (see Appendix B). Figure 5 indicates the estimated O&M cost for the examined plants as a function of cleaning plant (weight) yield.

3.4 Cost of Raw Coal Required Per Ton of Cleaned Coal

Operator's cost is defined as the operator's break-even cost for providing 1 ton of raw coal input to the cleaning plant. Such cost would include all appropriate expenses (e.g., royalties, labor and equipment, fair share of insurance, taxes, contributions to the Black Lung Trust Fund, and mine development costs). For the purposes of this study, profit was not included in the break-even cost of providing 1 ton of raw coal input to the cleaning plant.

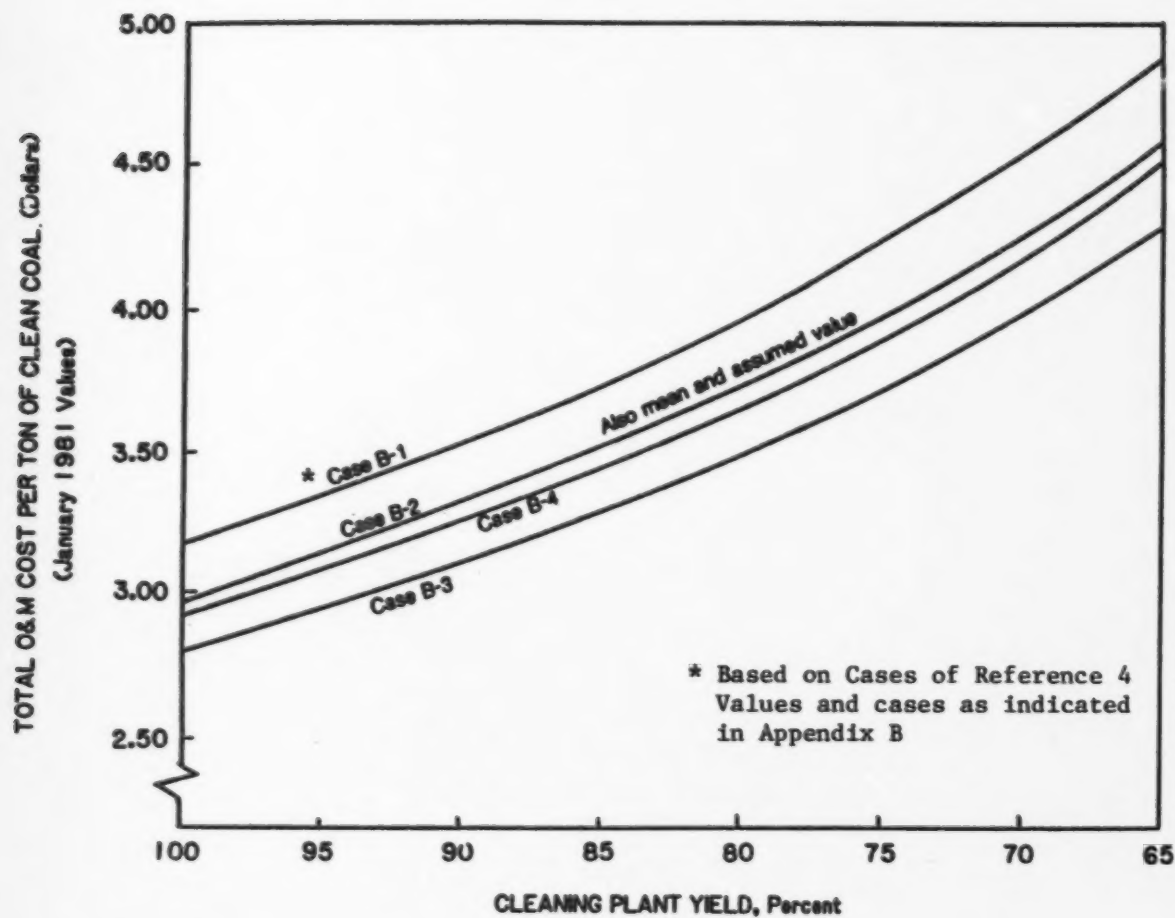


Figure 5

Operation & maintenance cost

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This was done since the study treats the mine and the coal preparation plant as an integrated operation under common ownership and therefore the coal is treated as work-in-process until it has been cleaned. However, one might argue that under different business management and/or accounting arrangements profit should be included in the raw coal input cost to the cleaning plant. To allow for such variations, a range of mine operator's costs to provide 1 ton of coal input was used in the analyses.

Since the clean coal yield is less than 100 percent of the raw coal input, it takes more than 1 ton of raw coal to provide 1 ton of cleaned coal. The cost of raw coal that is used to produce 1 ton of cleaned coal is simply equal to the per-ton operator's cost divided by the cleaning plant yield expressed as a decimal. Curves indicating the cost of raw coal required to produce 1 ton of clean coal are given in Figure 6. The "additional" raw coal cost to provide 1 ton of cleaned coal is the cost of the raw coal lost during the cleaning process and is equal to the operator's coal cost required to produce 1 ton of cleaned coal less the operator's per-ton coal cost.

3.5 State and Local Taxes and Insurance Allocated Against Each Ton of Cleaned Coal

Each ton of cleaned coal must support its share of cleaning plant insurance and State and local taxes. For this effort, an overall insurance and tax (I&T) level of 3 percent of the initial cleaning plant cost is employed for the illustrative case studies. The load attributable against each ton of cleaned coal (assuming cleaning plant operates at design capacity) is--

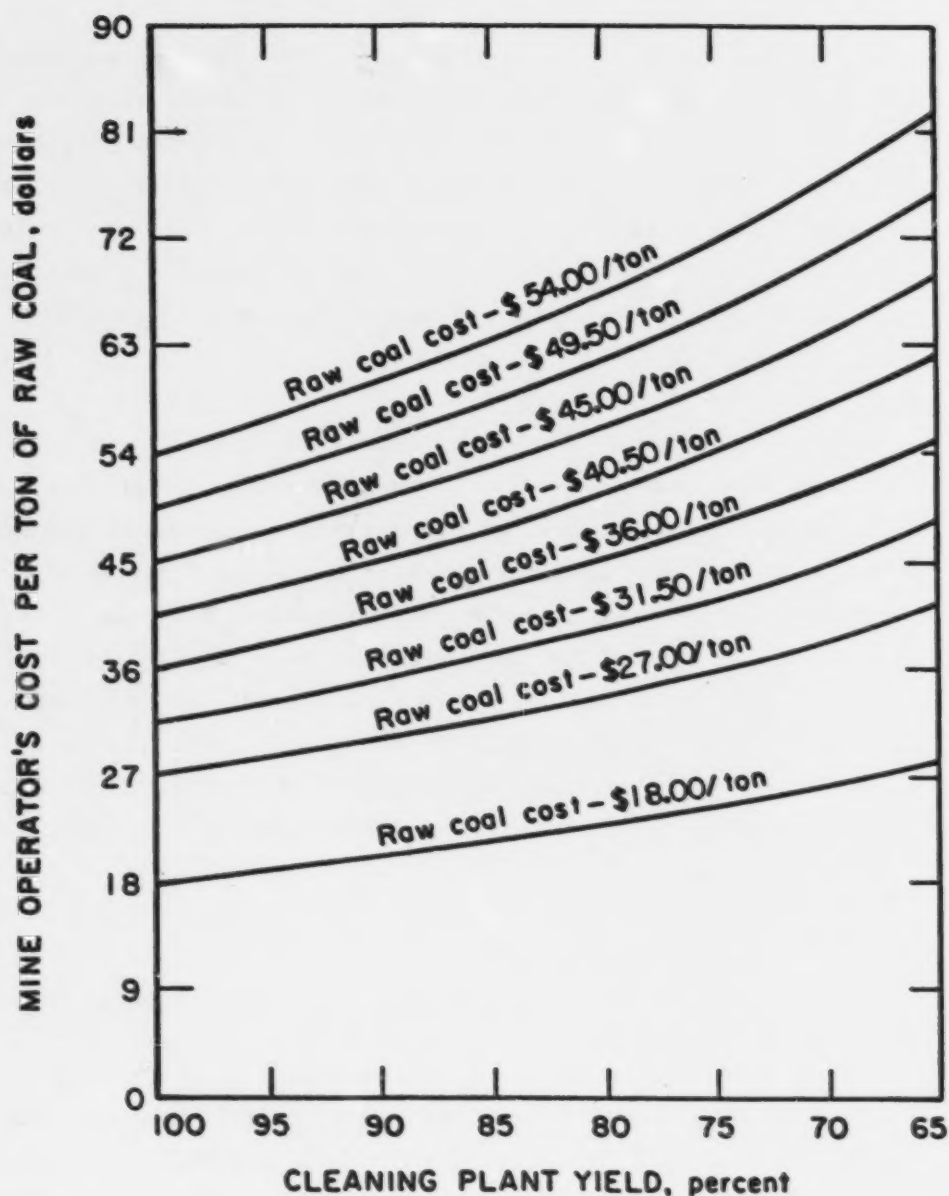


Figure 6
Cost of raw coal required to produce a ton of cleaned coal.

$$\begin{aligned}
 \text{I\&T load/ton} &= \frac{\text{cleaning plant cost/ton/hr. input capacity} \times 0.03}{\text{clean coal} \quad \text{operating hr./year} \times \text{yield (decimal value)}} \\
 &= \frac{\text{cleaning plant cost/ton/hr. input capacity} \times 0.03}{8,760 \times \text{utilization (dec.val.)} \times \text{yield (dec.val.)}}
 \end{aligned}$$

Thus, the insurance and tax load allocated against each ton of cleaned coal from a cleaning plant costing \$20,000 per ton-hour of input capacity is--

$$\begin{aligned}
 \text{I\&T/ton} &= \frac{\$600}{\text{clean coal} \quad 8,760 \times \text{utilization (dec.val.)} \times \text{yield (dec.val.)}}
 \end{aligned}$$

Figure 7 indicates the insurance and tax burden per ton of clean coal for a plant costing \$20,000 per ton-hour of input capacity. The I&T burden (Figure 7) is a function of plant utilization and plant yield.

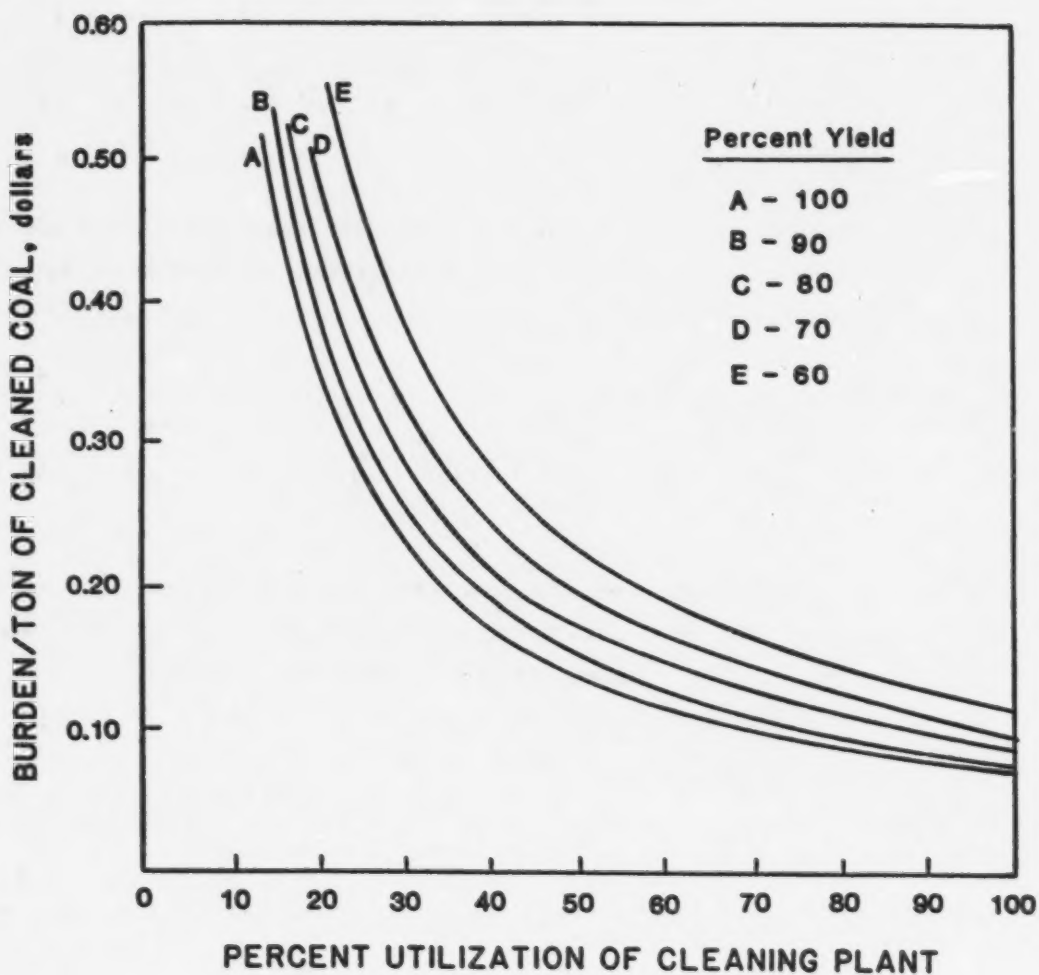


Figure 7
Tax and insurance burden/ton of cleaned coal,
plant cost-\$20,000 per ton-hour input capacity
and tax and insurance rate of 3%

4.0 EVALUATION OF ECONOMIC BENEFITS ASSOCIATED WITH THE USE OF CLEANED COAL

4.1 Economic Benefit Factors

The readily identifiable non-environmentally related monetary benefits attributable to a power plant burning cleaned coal (dried to or below the original raw coal moisture content) are as follows:

- Cleaned coal has a higher heat content per ton than the raw coal from which it is produced. Therefore, less cleaned coal will be required to provide a given heat content value.
- Less cleaned (high heat content) coal need be shipped for a given overall heat content value. Therefore, the cost of shipping will be less.
- Cleaning reduces the ash content of coal. The ash requiring disposal by the utility will be less due both to the lower ash content per ton burned and to the fact that fewer tons of coal will be burned (i.e., for a given heat content value).
- Less clean coal needs to be pulverized for a given heat content value, thus reducing the pulverizing costs. Further, cleaning often reduces the amount of harder particles in the coal, which should lessen wear on pulverizing equipment. However, the economic impact of this later factor associated with pulverizing is difficult to quantify and will therefore not be considered.
- Provisions of the 1978 UMW contract require mine operators pay \$1.385 to the Pension and Benefit Trust Fund for each ton of coal shipped from the mine. Cleaning, by raising the heat content of coal, will cause a decrease in the number of tons shipped (for a given heat content). Thereby, a savings equal to \$1.385 times the reduction in shipped tonnage will be attained.

- There is evidence that savings in power plant maintenance costs will be obtained, when using an eastern or mid-western coal, if the ash and sulfur contents of the coal are reduced. Thus, since physical cleaning reduces the ash and sulfur content of coal, lower power plant maintenance cost may result. In addition, for a given heat content value, fewer tons of cleaned coal need be handled by the power plant. Therefore, power plant units that are tonnage (utilization) limited will have an increased operational life.

There are a number of boiler/fuel situations that could uniquely benefit from using beneficiated (i.e., cleaned) coal. These are generally specific to a given situation and result from such conditions as: (1) the need for a higher heat content coal to permit achieving the design boiler capacity, and (2) the need to reduce ash to reduce slagging problems resulting from firing low ash fusion temperature coal in dry bottom boilers, etc. Generally, such problems result from utilizing a fuel not consistent with boiler coal specifications. Even though problems derived from burning a non-spec fuel can sometimes be alleviated by coal beneficiation (that produces a higher Btu and lower ash content product) such cases are unique and situations specific. For such cases, the benefits derived from coal cleaning generally apply to those situations where a poor match between boiler design and the utilized coal exists. Such a condition could develop by replacing bituminous coal with a lower sulfur, lower rank western coal or utilizing an available low ash-fusion-temperature coal in place of a more desirable higher ash-fusion-temperature coal. As indicated, such cases are very situation specific and therefore the unique benefits associated with coal cleaning (for such situations) are not further considered.

4.2 Increased Heat Content

An economic benefit readily identifiable to the purchaser of cleaned coal is equivalent to the f.o.b. raw coal price (i.e., price of unprepared coal) times the fractional increase in heat value of the cleaned coal over that of the raw coal. This is the equivalent f.o.b. mine raw coal price associated with the amount of coal that provides the equivalent heat increase.

If raw coal has an initial heat content of A per ton and if upon physical cleaning the heat content decimal increase is x , then the physically cleaned coal will have a heat content of $A(1 + x)$ per ton. The increase over the initial value is $A(1 + x) - A$ or Ax per ton. The fractional amount of cleaned coal that need not be shipped (i.e., the amount that offsets the heat content increase) is $Ax/A(1 + x)$ or $x/(1 + x)$. For the purposes of this study the factor $x/(1 + x)$ shall be termed the multiplier factor K . Therefore, the per-cleaned-ton benefit gained, a function of the raw coal f.o.b. price and the increase in heat content, is equal to the f.o.b. raw coal price (per ton) times $x/(1 + x)$. Figure 8 indicates the benefit gained as a function of raw coal f.o.b. mine price and the increase in heat content over the initial value.

4.3 Savings in Coal Transport Costs

Since cleaning increases the heat content of coal, less cleaned coal need be shipped to supply a given heat value. The amount of transport savings attainable by cleaning is a function of the increase in the coal heat content and the coal shipping costs.

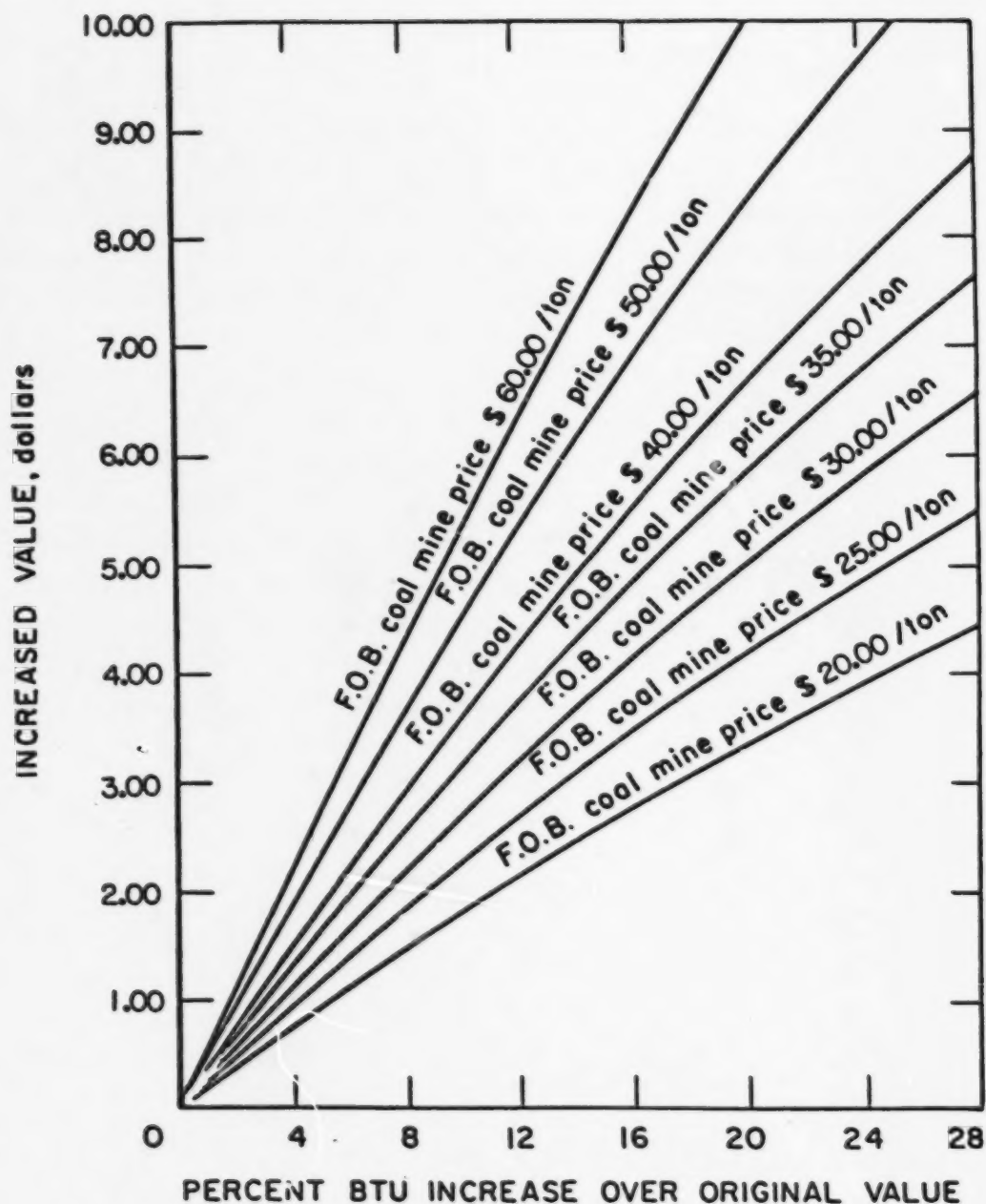


Figure 8
Added coal value due to increase in heat content.

The effective transport saving per ton of coal cleaned is equal to:

$$T.C. \times K$$

where T.C. = transportation cost per ton of coal

and K = the multiplier factor $\frac{x}{1+x}$

where x = decimal increase in coal heat content on cleaning (can be assumed to equal the decimal decrease in coal ash content).

Figure 9 indicates the multiplier factor K as a function of heat content increase.

Coal is currently shipped by train, waterway carrier, truck, and slurry pipeline. The transport mode or combination of modes employed in a given situation is usually determined by overall economic considerations. Coal loaded for shipping in 1978 as reported by mine operators is provided in Table 2.

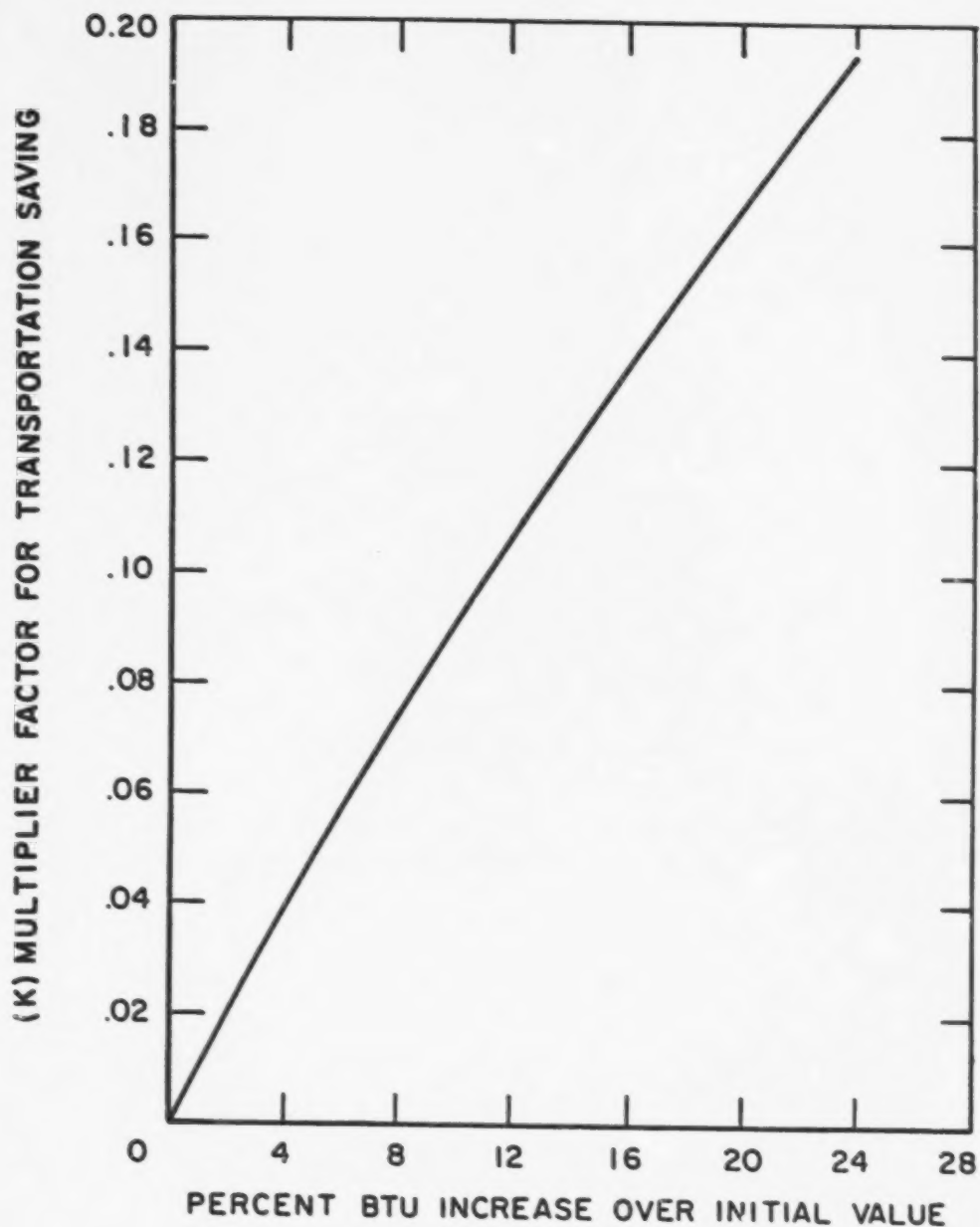


Figure 9

Effective savings in transport cost due to increase in coal heat content (equals shipping cost $\times$ K).

TABLE 2. COAL LOADED FOR SHIPMENT IN THE UNITED STATES, IN 1978, AS REPORTED BY MINE OPERATORS

	Million Short Tons
Total Railroad Shipments	402.6
Total Waterway Shipments	58.9
Shipped by truck to some railroad and water loading facilities and to final destination	105.1
Coal transported to electric utility plants adjacent to or near mine	87.3
All others*	11.1
Total production	665.0

*Includes coal used at mine for power and heat, made into beehive coke at mine, used by mine employees, used for all other purposes at mine, and shipped by slurry pipeline.

Since the majority of coal is shipped by the railroads, this study only considers the rail mode of shipping. The rail transportation costs used in this study are based on information reported by the railroad(s) that serve the indicated source/destination points as well as information obtained from the Interstate Commerce Commission and the Bureau of Labor Statistics.

Transportation costs to be realistic must reflect current conditions and practices that tend toward large annual tonnages along with economic train-load tonnage levels. The shipping rates used are based on rates for coal shipped in cars owned by the railroad (so as to reflect total costs) as reported by Reference 2

and updated by an appropriate price escalation index so as to reflect current costs. Information on coal transportation costs is provided in Appendix C.

4.4 Savings in Ash Disposal Costs

A coal fired utility must dispose of a substantial amount of ash. The total amount of ash is essentially equal to the amount of coal burned times the ash content expressed as a decimal value. Although some utilities have sold collected fly ash for use as a cement ingredient and bottom ash for use as an aggregate, the amount of ash produced by the electric utility industry far exceed the current and potential market for such ash. Since most utilities must bear the economic burden for disposal of their ash, this analysis makes that assumption.

Savings in ash disposal costs will be realized when cleaned coal is used (i.e., as opposed to raw coal). This saving is due to the following two reasons:

- Cleaning lowers the ash content of coal
- The heat content is raised by the cleaning process. Therefore, less coal needs to be burned for a given heat content value.

The effective saving in ash disposal cost per ton of cleaned coal burned is equal to the ash disposal saving per ton of coal burned, resulting from lower ash content, times a multiplier factor to account for the higher heat content of the cleaned coal. This multiplier factor is $(1 + x_1)$, where x_1 is the fractional increase

in heat content. If x_2 equals the decimal reduction in the coal ash content value on cleaning (*e.g., when the ash is reduced from 10% to 6% by weight, x_2 equals 0.04) then the total effective ash disposal savings per ton of coal burned is equal to the disposal cost per ton of ash times $(1 + x_1) (x_2)$. Assuming that a (x) fractional increase in heat content results from a (x) fractional reduction in ash content, then the total effective ash disposal savings per ton of coal burned is equal to the disposal cost per ton of ash times $x(1 + x)$.

4.5 Savings in Coal Pulverizing Costs

Evidence exists that in some cases reducing the amount of the harder impurities (e.g., pyrite) makes coal easier to pulverize. However, this effect does not appear to be universal, and the effect on pulverizing cost is not always discernible. It is currently estimated that it costs \$0.80 to pulverize 1 ton of coal, compared with \$0.50 2-1/2 years ago. This \$0.80 value is considered the total operation and maintenance cost.

The identifiable saving associated with cleaning coal results from the increased heat content of a ton of cleaned coal since less tonnage need be pulverized to supply a given heat value. The cost savings relationship (on a per ton basis) is--

Cost savings = \$0.80 times K,

where K = the multiplier factor $\frac{x}{1 + x}$

where x = decimal increase in coal heat content on cleaning (see Section 4.2).

As an example, consider that cleaning raises the heat content of coal by 10 percent; e.g., from 10,000 to 11,000 Btu per pound. In this case, the fractional decrease in the amount of coal that would compensate for the increase in heat content is $\frac{0.1}{1 + 0.1} = \frac{0.1}{1.1}$. The saving would be (on an equivalent per-ton basis) equal to $0.80 \times \frac{0.1}{1.1}$ or \$0.073 for each ton of cleaned coal burned.

4.6 Savings in Payment to Trust Fund

The mine operator pays \$1.385 to the Pension and Benefit Trust Fund for each ton of coal shipped to a consumer. If by cleaning, the heat content is raised by a decimal increase of x , then to satisfy a given heat content demand $\frac{x}{1 + x}$ less coal need be shipped. The savings attributable to each ton of cleaned coal is then equal to \$1.385 times K .

4.7 Maintenance Savings

Several data sources have been identified in which operating conditions and collected data are such as to permit a judgment relating sulfur and ash content in coal to power plant maintenance costs. All identified data is based on operating and cost histories of TVA utility operations.

Two sets of data are for identical steam power plants which burn coals of different ash and sulfur contents. These data are derived from two Tennessee Valley Authority (TVA) generating boiler units each having 200 Mw generating capacity. These two units,

both pulverized-coal-fired boilers, were placed in operation in the middle 1950's. Information on the coal-associated maintenance costs for the two plants is given in Tables 3 and 4. The data cover approximately 74 million tons of consumed coal. The economic data are contained in a February 1969 report (Reference 8) and are assumed to represent economic relationships during 1968. The available maintenance data with conclusions indicate:

- Maintenance costs for all the items listed in Table 4 are greater for the plant burning the higher ash and sulfur coal.
- The difference in maintenance cost during CY 1968 amounted to 11.63 cents per ton of coal. This difference in maintenance cost for the two units is almost two to one. This difference is not accounted for by the 5 percent difference in heat content value between the two coals.

TABLE 3. AVERAGE ANALYSES OF "AS-BURNED" COALS UTILIZED IN TWO IDENTICAL STEAM ELECTRIC PLANTS

	Plant A	Plant B
Moisture, percent	4.9	5.1
Volatile matter, percent	32.4	33.8
Fixed carbon, percent	52.1	47.7
Ash, percent	10.8	13.4
Sulfur, percent	1.0	2.7
Btu content (per pound)	12,680	12,053

Source: Reference 8

TABLE 4. COMPARISON OF 1968 MAINTENANCE COSTS IN IDENTICAL POWER PLANTS BURNING COALS OF DIFFERENT ASH AND SULFUR CONTENT

Items with Coal Associated Maintenance Costs	Maintenance Costs (Cents per Ton)	
	Plant A	Plant B
Primary Coal Crushing	0.34	0.76
Coal Conveyors	1.24	1.65
Boilers	3.72	6.42
Soot Blowers	0.80	2.55
Pulverizers	3.45	5.38
Burners	0.80	1.59
Air Preheaters	0.41	0.62
Bottom Ash Hoppers	0.55	1.73
Fly-Ash Collectors	0.80	1.52
Ash Disposal System	2.70	3.60
Coal Piping	0.80	1.42
TOTALS	15.61	27.24

Source: Reference 8

As indicated in Table 3, the average difference in ash content of the coals consumed by the two plants was 2.6 percent and the average difference in sulfur content was 1.7 percent. No information is available on maintenance costs with variations in ash and sulfur content for a given plant. However, these results suggest that substantial maintenance savings may be expected in steam plants capable of substituting lower sulfur and ash coal for their current steam coal.

More recently, more comprehensive analyses have been performed to define the effect of coal quality on maintenance costs at utility plants. These efforts, reported in part by Reference 9, are based on TVA data and indicate a direct relationship between utility plant maintenance cost and coal quality. Reference 9 indicates for the studied installations, as of mid-1978, that the maintenance saving for each one percent reduction in coal ash content was 5 to 10 cents per ton of coal burned. Correspondingly, for each one percent reduction in the coal sulfur content, the maintenance saving was 30 to 50 cents for each ton of coal burned. It should be emphasized that these values are based on initial investigations and additional analyses are being pursued.

The recent efforts are more comprehensive than the earlier (Reference 8) analysis and certainly reflects more current economic conditions. The Reference 9 values of differential maintenance cost versus coal quality will be the basis for this analysis.

From mid-1978 to the end of 1980 the Engineering News Record (ENR) Building Cost Index increased by 21 percent. The ENR Construction Cost Index increased by 22 percent. Escalating the average differential maintenance cost values of Reference 9 by the average increase in the two ENR indexes to reflect assumed January 1981 values, we have:

Maintenance cost savings for each one percent
reduction in coal ash content (January 1981 value)
= $\$0.075 \times 1.215 = \$0.09$ per ton of coal burned

Maintenance cost savings for each one percent
reduction in coal sulfur content (January 1981 value)
= $\$0.40 \times 1.215 = \$0.49$ per ton of coal burned

These are the values that are used in the provided analyses.

5.0 EVALUATION OF COSTS ASSOCIATED WITH FLUE GAS DESULFURIZATION

5.1 Flue Gas Desulfurization (FGD) Plant Costs

Only limestone FGD systems are considered by this effort. This is due to the preponderance of this type of system for old as well as new installations. For assessment purposes, information on capital cost and related data used in developing capital-cost-scaling relationships were obtained from References 10, 11, and 12, as well as from discussions with the TVA Division of Energy Demonstration and Technology, Office of Power. Some obtained data were used to develop the desired scaling relationship (e.g., relative capital cost vs. capacity), while other data were used to establish a base cost value for use with the scaling relationship. In addition, manufacturers of FGD systems were consulted to verify the reasonableness of study used values.

Capital costs for a number of limestone FGD systems, all designed for 90% SO₂ removal from coal-fired power units of various sizes and burning varying sulfur content coals, are contained in Reference 12. These data, all representing the same time period, were used for developing installed FGD system capital cost scaling relationship. Capital cost data, derived from Reference 12, are presented in Tables 5 and 6. Table 5 presents FGD plant capital cost data for different capacity power units all burning 3.5% sulfur coal with 90% SO₂ removal and pond disposal of waste solids. Table 6 presents FGD plant capital cost data for 500 MW_e power units burning different sulfur level coals with 90% SO₂ removal and pond disposal of waste solids. The capital investment breakdowns are provided in Appendix D.

TABLE 5

LIMESTONE PLANT CAPITAL COSTS (\$000)

(3.5% S in coal, 90% SO₂ removal, pond disposal of waste solids)

	<u>200 MW_e</u>	<u>500 MW_e</u>	<u>700 MW_e</u>	<u>1000 MW_e</u>
Direct Investment Less Reheater	12,950	27,244	36,769	49,180
Direct Investment For Reheater	556	1,292	1,824	2,519
Indirect Investment (Including Contingency)	7,440	13,693	17,874	23,027
Other Capital Charges	4,337	8,743	11,713	15,504
Land	554	1,098	1,408	1,844
Working Capital	<u>465</u>	<u>1,013</u>	<u>1,379</u>	<u>1,867</u>
TOTAL	26,302	53,083	70,967	93,941

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TABLE 6

LIMESTONE PLANT CAPITAL COSTS (\$000)

(500 MW_e, 90% SO₂ removal, pond disposal of waste solids)

	<u>3.5%</u> <u>Sulfur Coal</u>	<u>2.0%</u> <u>Sulfur Coal</u>	<u>1.4%</u> <u>Sulfur Coal</u>	<u>0.8%</u> <u>Sulfur Coal</u>
Direct Investment Less Reheaters	27,244	22,989	20,817	19,875
Direct Investment For Reheaters	1,292	1,287	1,283	1,315
Indirect Investment (Including Contingency)	13,693	12,054	11,196	10,831
Other Capital Charges	8,743	7,658	7,091	6,870
Land	1,098	675	478	364
Working Capital	<u>1,013</u>	<u>848</u>	<u>769</u>	<u>740</u>
TOTAL	53,083	45,511	41,634	39,995

For process plants making identical products by identical processes, the following relationship often provides a reasonable relationship between cost and capacity.

$$\frac{\text{Cost A}}{\text{Cost B}} = \left[\frac{\text{Capacity of A}}{\text{Capacity of B}} \right]^x$$

where x is a constant less than one.

The validity of this relationship, as applying to Reference 12 (i.e., Table 5) cost data, would be established if the log (cost D) versus log (capacity D) plots linearly, where D refers to any given unit. If log (cost D) versus log (capacity D) plot linearly then for analysis purposes we can estimate the capital cost of a unit of arbitrary capacity from the cost and capacity of a known unit that provides an equivalent SO_2 removal efficiency when treating flue gas of equal SO_2 concentration.

Figure 10 is a plot of log (capital cost) versus log (capacity) data contained in Table 5. Values are plotted of capital costs with and without flue gas reheaters. As seen by Figure 10, the plot is indeed linear with slope = 0.79. Therefore, the relationship

$$\frac{\text{Cost A}}{\text{Cost B}} = \left[\frac{\text{Capacity A}}{\text{Capacity B}} \right]^{0.79}$$

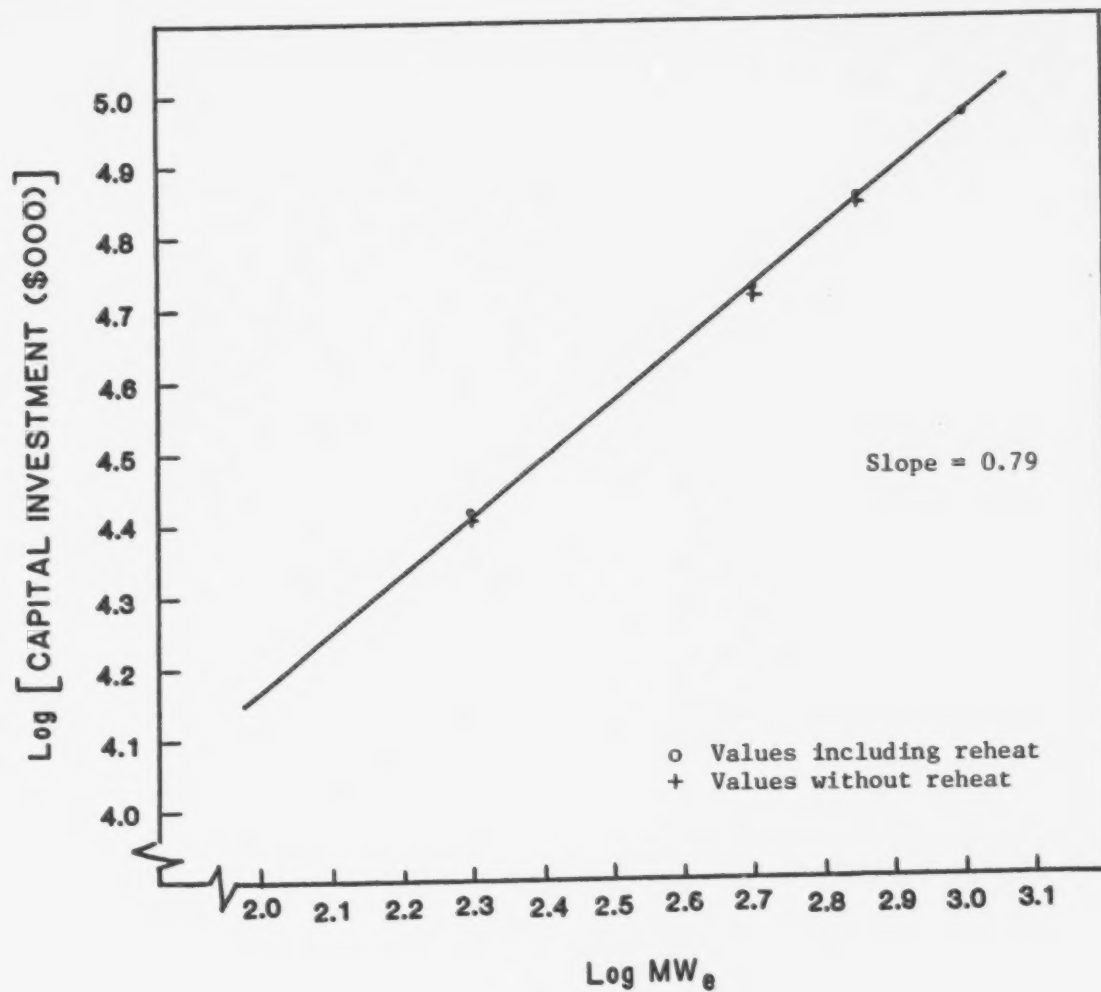


Figure 10

Log (Capital Cost) vs. Log (Capacity)
of 90 Percent SO₂ Removal FGD Systems

(Per Table 5)

will be used to estimate the capital cost of FGD units of various sizes rated to remove 90% of the SO_2 from power units burning 3.5% sulfur coal.

It is also necessary to be able to scale the capital cost of an FGD system (with a given SO_2 removal efficiency) so as to provide cost as a function of coal sulfur content. Specifically, cost of a given capacity system with 90% SO_2 removal capability is required. Table 6 based on Reference 12, indicates the capital costs of limestone FGD plants that would provide 90% SO_2 removal from 500 MW_e generating units burning varying sulfur content coals. Table 7 provides the capital cost versus designed sulfur content for these plants when adjusted to the same flue gas flow rate. A plot of the cost versus sulfur content when normalized for the same flue gas flow rate is given by Figure 11. The plot is essentially linear and the resulting cost versus coal sulfur content relationship will also be used for FGD cost scaling purposes.

It should be noted that with the exception of FGD slurry components, the cost of an FGD system is basically dependent on the flue gas flow rate in the absence of other considerations. However, this study assumes pond disposal of scrubber effluents and the ponding cost plus the slurry handling cost do result in a significant variation in FGD capital cost with coal sulfur content for the considered 90% SO_2 removal capability.

Even though the cost values contained in References 10 and 12 are based on recent investigations, additional work by the same investigators (Reference 13) has provided an escalation factor based on revised design premises. Changes in technology, design philosophies, economic conditions, environmental mandates, etc.,

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TABLE 7

COST VERSUS PERCENT SULFUR IN COAL FOR 500 MW_e 90 PERCENT REMOVAL FGD SYSTEMS

Sulfur Content (% S by wt.)	Coal Btu per pound	Total Investment (\$000)	Flue Gas Flow Rate 1000 ft ³ /min	Gas Flow Rate Normalized to Higher Btu Coal Value	Cost Adjusted to Normalized Flow Rate (\$000)
0.8	9,500	\$39,995	1,023	1.034	\$38,650
1.4	12,600	41,634	989	1	41,634
2.0	11,000	45,511	994	1.005	45,300
3.5	10,500	53,083	999	1.010	52,562

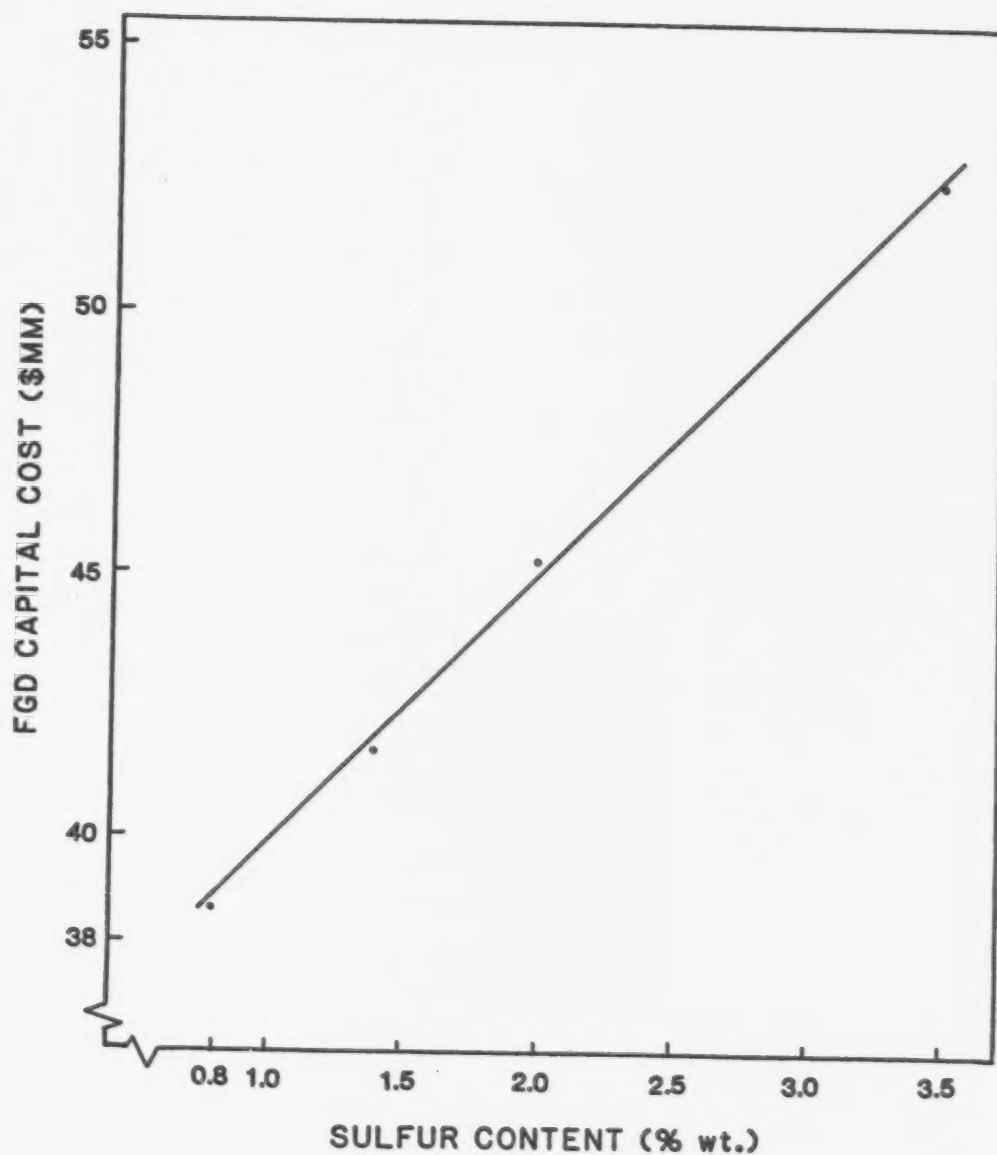


Figure 11

Estimated capital cost of 90 percent SO_2 removal
500 MW FGD systems vs. design coal sulfur content
(as based on 12,600 Btu/lb bituminous coal)

have necessitated the need for continuing reassessment of installed FGD system cost. Even so, it must be stressed that the provided costs are only analytical estimates. The cost for a given installation will undoubtedly be specific to the conditions and requirements of the particular application. For this study, the costs as defined in this chapter are used.

Since TVA has been revising their basic design premises, the base case FGD capital cost estimate as previously indicated, has been upgraded accordingly. The base case cost (i.e., Table D, Appendix D) is the estimated capital cost for a FGD system providing 90% SO₂ removal for a 500 MW_e new coal-fired power unit burning 3.5% sulfur, 10,500 Btu per pound coal with pond disposal of waste solids. The cost basis is Midwestern for mid-1979. To be conservative, the study revisions are substantially less than those indicated by Reference 13. The revisions considered are as follows:

<u>Factor</u> *	<u>% Change</u>	<u>% Cumulative Change</u>
New power plant design premise (including higher Btu/lb. coal)	4	4
Additional reliability factor (spares and flue gas bypass)	21	25.8
Spray tower instead of mobile- bed absorber	8	35.9
Eastern rather than midwestern site	2	38.6

The base case (500 MW_e new coal-fired unit, 3.5% S coal, 90% SO₂ removal, pond disposal of waste solids) cost is for a plant fully on-line in January 1981. The base case capital cost with considered revisions becomes \$53,083,000 (per Table D, Appendix D) times 1.386 = \$73,573,000 or \$147 per kilowatt installed capacity. Based on the provided rationale, cost scaling for another size "A" is defined by:

$$\text{Cost A} = \$73,573,000 \left[\frac{\text{Capacity A (in MW}_e\text{)}}{500} \right]^{0.79}$$

Subsequent cost scaling to reflect a different coal sulfur content is based on Figure 11. The scaling factor, based on this figure, is:

$$y = 0.098 x + 0.657$$

where

y = scaling (i.e., multiplier) factor

x = % sulfur by weight in coal (i.e., as burned)

Therefore, the estimated capital cost for a 90% SO₂ removal system for a new plant is defined for assessment purposes as:

Cost = Cost of base system x size scaling factor x sulfur scaling factor

$$\text{Cost} = (\$MM) = \$73.573 \left[\frac{\text{MW}_e \text{ flue gas capacity}}{500} \right]^{0.79} \text{ times} \\ \left[0.098 \times ZS + 0.657 \right]$$

The estimated cost of a FGD installation for a retrofit application is the above value times 1.25. It is assumed that a retrofit FGD system would cost 25% more than an equivalent system for a new plant. It should be noted, that there is considerable variability in additional cost for a retrofit application. In many cases, very substantial additional effort is required including tear down, rebuild, replacement of structures and facilities, etc. Published estimates have generally indicated a 20 to 25% increase in cost. Discussions with utilities have indicated increased costs as high as 100 percent. The cost for a given situation is very site specific. The 25% increase for a retrofit over a new installation value should provide a conservative analysis by understating the potential saving through the use of FGD combined with coal cleaning.

Once the capital cost associated with the FGD system (for either a new or an existing powerplant) is determined, it is necessary to properly allocate this cost annually over the reasonable life expectancy of the installation. The annual percentage(s) (i.e., of the capital cost) are based on Reference 2 with updating based on Reference 10.

5.2 Assumed Annual Capital Charges For Financing An FGD Plant
That Would Be Operational In January 1981

Years Remaining Life	<u>As Percentage of Original Investment</u>				
	<u>28</u>	<u>25</u>	<u>20</u>	<u>15</u>	<u>10</u>
Depreciation-Straight Line (based on usable life of power unit)	3.57	4.00	5.00	6.67	10.00
Interim Replacement (equipment having less than 30-year life)	0.6	0.4	--	--	--
Insurance	0.5	0.5	0.5	0.5	0.5
Property Taxes	<u>1.5</u>	<u>1.5</u>	<u>1.5</u>	<u>1.5</u>	<u>1.5</u>
Total Rate Applied to Original Investment	6.17	6.40	7.00	8.67	12.0

<u>As Percentage of Outstanding Depreciation Base</u>	
Cost of Capital (capital structure assumed to be 60% debt and 40% equity)	
Bonds at 12% Interest	7.2
Equity at 14% Return to Stockholder	5.6
Taxes	
Federal (50% of gross return or same as return on equity)	5.6
State (national average for states in relation to federal rates)	4.5
Total Rate	22.9
Rate Applied on an Average Basis	11.45

Combining the various annual capital charges for financing gives a set of total annual percentages applied on an average basis for each of the possible installations life expectancies as follows:

For 28 years	=	6.17 + 11.45	=	17.62
For 25 years	=	6.40 + 11.45	=	17.85
For 20 years	=	7.00 + 11.45	=	18.45
For 15 years	=	8.67 + 11.45	=	20.12
For 10 years	=	12.00 + 11.45	=	23.45

5.3 Flue Gas Desulfurization Costs Per Ton of Coal Burned

Having established FGD cost scaling relationships and the other relevant cost components, the FGD cost burden on each ton of coal burned can be estimated for a given coal-burning installation. The following FGD costs per ton of coal burned are based upon an electric utility heat rate of 10,000 Btu/kwh.

5.3.1 Capital Cost Per Ton of Coal

$$= \frac{\text{capital cost (\$)} \times \text{annual \% of orig. investment on avg. basis}}{\text{tons of coal burned per year} \times 100}$$

5.3.2 Electricity Cost

Reference 12 contains detailed cost breakdowns of the annual revenue requirements for a number of limestone FGD systems providing 90% SO₂ removal for 500 MW_e plants burning different

bituminous coal of different sulfur content. The electricity cost for a full scale FGD system equates to between \$1.18 and \$1.29 per ton of coal burned when the actual cost are corrected to reflect the same flue gas flow rate (i.e., same coal quality and therefore the same boiler coal throughput tonnage). The above value is based on electric power charges of 30 mills per kwh. The average value of the cost range equals \$1.22 per ton of coal for full flue gas scrubbing. The \$1.22 average value is the value associated with 11,000 Btu per pound coal and is used for cost assessments. The extremes (\$1.18 and \$1.29) differ from the utilized value by not more than 7¢ per ton, an insignificant amount compared with other costs. The assumed FGD electricity cost in dollars per ton of coal burned is then equal to $1.22 \times \frac{\% \text{ of Flue Gas Cleaned}}{100} \times \frac{\text{Charge per kwh (in mills)}}{30}$. This equates to electricity cost (i.e., dollars) per ton of coal burned of: $0.0004067 \times \% \text{ of Flue Gas Cleaned} \times \text{Cost of a kwh of electric energy (in mills)}$.

It should be noted that even though it was assumed that the required electric power is independent of coal sulfur content, there will be a slight variation due to varying slurry level requirements. However, the variation in overall power requirements is small (1 to 2% in overall electric power requirements) and the overall economic effect is inperceptable.

5.3.3 Fuel Cost For Stack Gas Reheat

Flue gas is normally discharged to the stack at 250° to 300°F. The temperature is selected to remain above the dew point in order to reduce corrosion and permit carbon steel to be used for fans, ducting, and stack lining.

When a wet scrubber is inserted between the air heater and stack for SO_2 removal, the flue gas exiting the scrubber is saturated with water and cooled to the saturation temperature of about 125°F. To insure proper dispersion of flue gases in the atmosphere and reduce stack corrosion, flue gases from the absorber in the wet FGD processes must be heated to about 175°F. before the entering the stack. It is possible to effect considerable savings if untreated gas that bypasses the FGD absorber is mixed with the cooler FGD treated gas before entering the stack. Reference 11 indicates that up to 70% of the total flue gas can be scrubbed and returned to 175°F. without use of additionally supplied reheat energy. The reheat saving will be dependent on the amount of flue gas that is allowed to bypass the FGD absorber.

Reference 11 indicates that the energy used for flue gas reheat when all the gas is scrubbed (for all practical analysis purposes) is proportional to the flue gas flow rate. For a 500 MW_e plant operating at capacity with full scrubbing using inline steam reheat, essentially 70 MMBtu of reheat energy per hour is required. The amount scales linearly with the amount of flue gas reheated.

As indicated in Reference 11, if less than 70% of the flue gas is scrubbed, additionally supplied reheat energy is not required. This is indicated by Figure 12. Therefore, the amount of reheat energy required is assumed to be as follows:

- Less than 70% of flue gas scrubbed - no reheat required
- When 70% to 100% of flue gas is scrubbed the percent of the full reheat value (based on Figure 12) is equal to $(3.3333 \times \% \text{ of flue gas scrubbed} - 233.333)$.

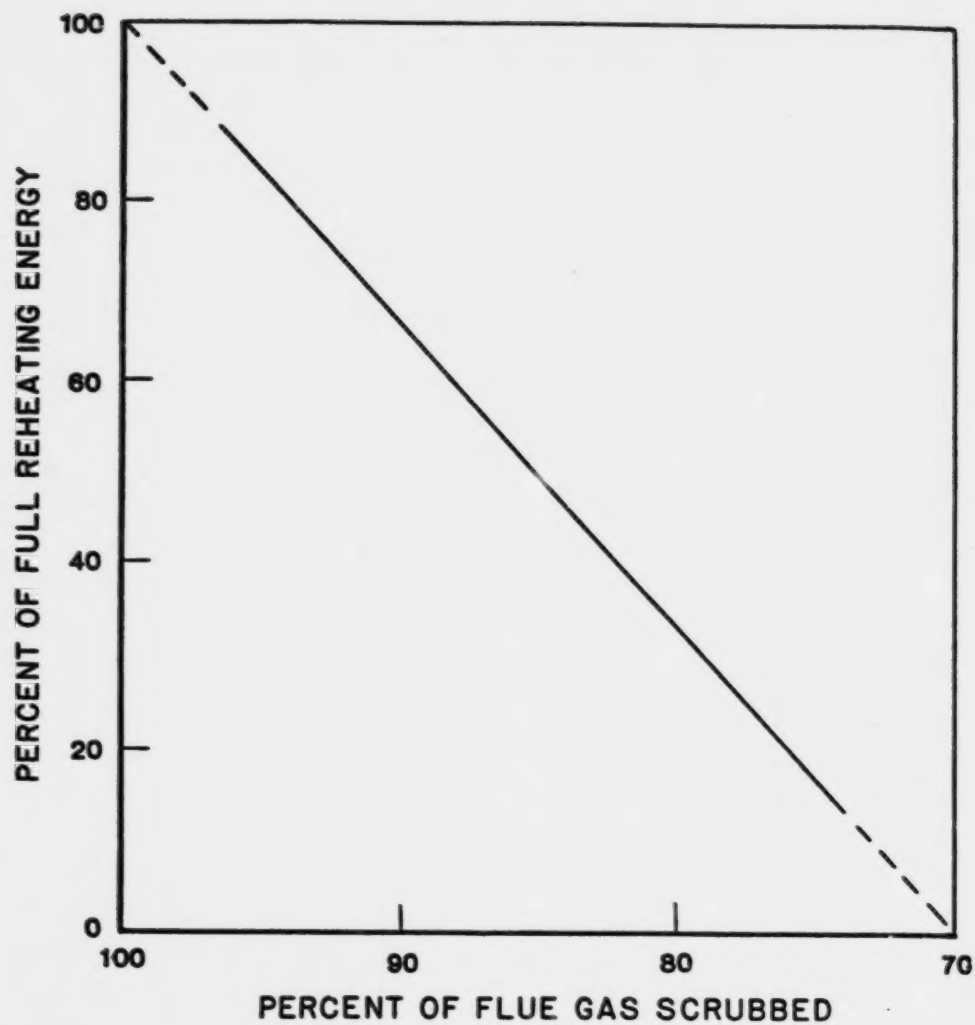


Figure 12
Dependence of flue gas reheating energy
on proportion of flue gas scrubbed

The energy required for reheating all the flue gas from a 500 MW_e plant using a limestone FGD system is estimated (as-based on Reference 12) to be 70.0 MMBtu per hour at a cost of \$2.00 per MMBtu. The maximum amount (i.e., full reheat) scales linearly with plant capacity. The amount for less than full flue gas cleaning depends on the amount of flue gas that bypasses the scrubber and is, as indicated, zero when less than 70% of the flue gas is scrubbed. The reheat cost estimate in dollars per hour is:

$$\text{Plant size in MW}_e / 500 \times 70 \text{ MMBtu/hr} \times \$2.00/\text{MMBtu} \times \text{bypass reheat factor (per Figure 12)} = \text{Plant size in MW}_e \times 0.28 \times \text{bypass reheat factor (per Figure 12)}.$$

The cost per ton of coal burned is merely the above cost value divided by the tons of coal burned per hour.

5.3.4 Raw Materials

Limestone costs are based in part on Reference 12. The amount of limestone required for a given FGD system type is proportional to the amount of sulfur removed. The amount of limestone is based on a constant mol/mol SO₂ removal value (i.e., constant stoichiometric ratio value of 1.4). An assessment of the Reference 12 limestone FGD analyses indicated the use of an essentially constant stoichiometric ratio value.

The amount of limestone required per ton of coal burned for a FGD system removing 90% of the SO₂ from all the flue gas as based on Reference 12 is as follows:

$$\frac{\text{Tons of limestone}}{\text{Tons of Coal}} = 0.0375 \times \%S$$

The amount of limestone per ton of coal burned with partial flue gas cleaning is equal to the above times the decimal portion of the total gas that is cleaned, or:

$$\frac{\text{Tons of Limestone}}{\text{Ton of Coal}} = 0.000375 \times \%S \times \%FGC$$

where $\%S$ = percent sulfur in coal by weight
 $\%FGC$ = percent of the total flue gas cleaned

The limestone cost per ton of coal burned is simply the above times the per ton cost of limestone.

5.3.5 Operating Labor (including supervision)

Operating labor for a 500 MW_e FGD system is based on a minimum of 3 persons available at all times. This is assumed to require an operating labor force of 12 persons to provide for adequate staffing while providing for vacations, sick time, etc. Assuming an average of 1800 productive hours per person-year, the requirement equates to 21,600 total person-hours per year. The estimated increase in staff for up to 300 MW_e additional FGD capacity is 4 person-years or 7200 person-hours. In a like fashion, maintenance requirements are estimated to decrease by 7200 person-hours to a value of 14,400 person-hours for a 200 MW_e or smaller FGD system. In essence, FGD plant personnel would

necessarily be available in increments of a person-year (i.e., 1800 person-hours), with uniform staffing required. This equates to staffing increments of 4 persons (depending on plant size) in order to provide a level staffing force.

Therefore, the following operating labor requirements are assumed:

<u>MW_e Portion of Flue Gas Treated</u>	<u>Labor Requirements (Person-hours)</u>
0 to 200	14,400
200+ to 500	21,600
500+ to 800	28,800

The average January 1981 cost of operating labor including overhead is estimated at \$13 per person-hours. The labor cost per ton of coal burned is simply the total labor cost divided by the tons of coal burned per year. As an example, assume a 500 MW_e plant with 20% of the flue gas cleaned. This equates to the equivalent of 100 MW_e of flue gas cleaned. The operating labor cost per ton of coal burned would be:

$$\text{Cost per ton of coal} = \frac{14,400 \times \$13}{\text{Total tons burned per year}}$$

5.3.6 Maintenance Cost

Maintenance costs per year fall into two categories: 1) labor and materials, and 2) supplies. Labor and materials per year

are estimated at 4 percent of the fixed investment cost (in terms of current dollars) and supplies are estimated at 15 percent of the labor and materials value (i.e., 0.6 percent of the fixed investment in terms of current dollars). The cost per ton of coal burned is merely the sum of the yearly values divided by the number of tons per year.

5.3.7 Other Minor Charges

The cost of process water, analyses, etc., as of January 1981, is estimated to not exceed 10¢ per ton of coal for a coal-fired boiler plant with full FGD scrubbing. For partial FGD scrubbing, these costs per ton of coal burned are estimated to be:

$$\text{Cost per ton of coal} = \$0.10 \times \frac{\% \text{ of flue gas scrubbed}}{100}$$

6.0 CASE STUDY METHODOLOGY

6.1 Basis and General Considerations

As previously stated, the basic objective of this effort sponsored by DOE is to establish a methodology for comparing the economics of combining coal cleaning with flue gas desulfurization (FGD) as compared with FGD alone in meeting required SO_2 emission limitations from steam raising boilers. In addition to the methodology development, a number of hypothetical case studies based on realistic parameters are provided to both indicate the assessment procedures and potential overall attractiveness of combining coal cleaning with flue gas desulfurization. Since the largest user of coal in this country is the electric power generating industry, the study was directed at this economic sector.

Toward this end, studies were made of the cost factors associated with coal cleaning (Section 3 and Appendix B). An analysis of such costs quite logically leads into a study of the many benefits associated with physical cleaning of coal. Major benefits of physical cleaning include reduced transportation cost for the same heat content, higher Btu per unit weight, reduction in utility pulverizing costs, savings in utility maintenance cost, reduced payments to miners' benefit fund, and savings by the utility in ash disposal costs.

Following the analysis of cleaning cost and benefit factors, an evaluation of the costs associated with flue gas desulfurization (FGD) systems of various sizes was conducted. This evaluation provided reasonable estimates of the capital costs associated with

constructing FGD systems, depending on the particular size of the FGD system, the age of the utility plant, and the sulfur content of the flue gas to be treated. As has been indicated in Section 5 on the economics associated with FGD, a scrubber installed on a new plant is less expensive than one installed as a retrofit to an existing facility. These differences in cost include the inefficiencies of working around existing piping and other obstructions. In addition, operation and maintenance aspects of FGD systems were considered to arrive at a methodology for estimating such costs for plants of varying sizes burning coal of different sulfur contents.

Having identified and quantified the costs and benefits associated with coal cleaning and FGD, the next step was to derive an accounting tabulation methodology to define the SO₂ control cost as based on a) coal cleaning combined with FGD and b) FGD used exclusively. It should be noted that the same philosophy is used for both of the above cases. As an example, for both cases the size of the FGD system (with a consistent percent of margin capacity) is only that required to meet standards. The attempt is to insure that the economics are not biased to favor the coal cleaning plus FGD concept.

A final step before commencing the actual economic analysis on a case-by-case basis was to arrive at representative user locations. To accomplish this, we considered the following 20 states: Alabama, Delaware, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. These were considered in that they represented reasonable transportation distances from and had been historically served by Appalachian and Interior Coal sources.

BEST DOCUMENT AVAILABLE

After ascertaining the legal emission levels in each of the potential user states, it was possible to determine the extent to which a combination of reasonable cleaning and FGD would suffice. Such analysis was conducted for each source-user combination on the basis of both a new and existing facility. In addition, each case, as previously indicated, was analyzed from the standpoint of using FGD exclusively. This provided comparative economics of the two approaches to meeting environmental standards on both new and existing coal-burning utilities.

To determine where within each of the potential user states coal from the selected regions might practically be consumed, publications from the National Coal Association, the Bureau of Mines, the Department of Energy, and other sources were consulted. These gave specific locations of large power generation facilities which were designated as "coal use areas" in each of the case studies. At this point, it was necessary to determine the general locations from which these using locations had historically obtained their coal. To accomplish this, publications were reviewed such as Bureau of Mines Information Circular 8614 (References 14 and 15). From these same sources, shipping costs on a per-ton basis were derived. So as not to distort the impact of this factor, only large-volume transportation cost information was used. Since this shipping information covered the 1972 period, it was necessary to update these figures to January 1, 1981, using the Bureau of Labor Statistics Index of Coal Transportation by Rail. The means for accomplishing this is covered by Appendix C.

The analysis (as previously indicated) is based on economic values as of January 1, 1981. Therefore, the various cost estimates are based on all facets coming together on January 1, 1981.

To this end, coal cleaning plants and FGD systems capital cost and financing parameters are those in being at the time construction of these units would normally commence. This would typically be 1-1/2 to 2 years prior to the date of the economic determination point. Other cost such as labor, coal costs, maintenance, supplies, etc., would be the values at the determination point (January 1, 1981).

6.2 Analytical Approach

The net cost of controlling SO₂ emissions by coal cleaning combined with FGD is equal to:

Cost of cleaning coal
plus
Cost of flue gas desulfurization
less
Benefits of using cleaned coal

The identified and quantified cost and benefit components in terms of per ton of coal burned are as follows:

Cost of Cleaning Coal

- Amortization of Cleaning Plant Capital Cost
- Operation & Maintenance Cost of Cleaning Plant

- Cost of Raw Coal Lost in Cleaning Process
- Taxes & Insurance Costs of Cleaning Plant

Cost of Flue Gas Desulfurization

- Amortization of Scrubber Cost
- Fuel & Electricity Cost
- O&M Cost
- Flue Gas Reheat Cost

Benefits From Using Cleaned Coal

- Added Coal Value Due to Increased Heat Value
- Transportation Saving Due to Increased Heat Content
- Saving in Ash Disposal Cost
- Saving in Pulverizing Cost
- Saving in Pension Fund Payment
- Saving in Boiler Plant Maintenance Cost

The identified and quantified cost of using FGD alone to control SO_2 equals the sum of the following cost components:

- Amortization of Scrubber Cost
- Fuel & Electricity Cost
- O&M Cost
- Flue Gas Reheat Cost

6.3 Case Study Analysis - An Example

Having provided the basic cost components used for the case studies, a step-by-step example will be provided. In the particular example given, the new steam-electric plant is assumed to be burning coal which has been physically cleaned with the flue gas passing through a stack gas scrubbing system (flue gas desulfurization) to the extent necessary to achieve the required sulfur dioxide emission level. This case appears in its entirety as Case Number 5A at the end of this section and in Appendix A and for the purposes of explanation, the same numerical headings and nomenclature will be used.

- 1.0 CASE CONDITIONS: Case Number 5A
- 1.1 Coal Use Area: Grand Rapids, Michigan
- 1.2 Emission Standard: New Plant 1.2 lb. SO₂/MMBtu
- 1.3 SO₂ Control Method: Combined use of physical coal cleaning followed by flue gas desulfurization
- 1.4 Origin of Coal: State-West Virginia; County-Preston; Coalbed-Upper Freeport. This county source is consistent with past coal procurements for the indicated coal use area.
- 1.5 Raw Coal:
- | | |
|-------------------------------|----------|
| Sulfur | - 2.13% |
| Ash | - 17.6 % |
| MMBtu/ton | - 23.50 |
| Lbs of SO ₂ /MMBtu | - 3.63 |

(These values are on an as-received basis.)

After selecting a reasonable source for the coal in each case, data were obtained on a specific coal from Bureau of Mines Report of Investigations RI 8118 with the ash,

sulfur and Btu values subsequently adjusted for the total moisture level of the raw coal.

1.6	<u>Clean Coal:</u>	Cleaning plant (wt.) yield	- 82.5 %
		Cleaning plant Btu recovery	- 92.3 %
		MMBtu/ton	- 26.30
		Sulfur	- 0.94%
		Ash	- 8.4 %
		Lbs of SO ₂ /MMBtu	- 1.43
		Unit Wt. Btu increase on cleaning	- 11.9 %

The clean coal characteristics are based on washability curves with a cleaning cut point defined by a 45° tangent to the Btu-yield versus sulfur-content curve (see Appendix E). That is, the coal is cleaned to the point where Δ sulfur content/ Δ Btu-value exhibits a sharp change. The above clean coal values reflect the moisture content of the cleaned coal.

1.7 Coal Transportation From Source to Use Area:

Distance - 575 miles
Cost per ton - \$9.20

Coal transportation distance and cost are based on past distance and cost data for same coal-source county and use area locations with update based on Bureau of Labor Statistics coal-transportation cost index. The data are based on large annual coal shipments with the distance in rail miles confirmed through a railroad map.

- 1.8 Electric Utility Plant: For the purpose of study, all cases are based on a 500 MW_e plant size. The assumed remaining boiler life (i.e., new plant) is 25 years, utilization is equivalent to 7000 hours at full load which equates to a 79.9% load factor. The coal burned per year is 1.33 million tons as based on a heat rate of 10,000 Btu/kwh, 7000 hours per year and the as-burned coal Btu value. The value is equal to:

$$\frac{10 \times 10^6 \text{ Btu/Mwh} \times 7000 \text{ hours/year} \times 500 \text{ MW}_e \text{ capacity}}{26.30 \times 10^6 \text{ Btu/ton of coal burned}}$$
$$= 1.331 \times 10^6 \text{ tons per year}$$

- 1.9 Utility Ash Disposal Cost: In all cases it is assumed that utility ash disposal cost amounts to \$7.00 per ton, as based on past and recently obtained information.

- 1.10 Coal Cleaning Plant: The capital cost of the considered plant [3/8" T.S. (topsize) for case 5A] at the time a commitment would have to be made for the plant to be operational by 1/1/81 is estimated to be \$20,000 per ton per hour input capacity when the overall input capacity is at least 500 tons per hour. It is assumed the plant would operate 260 days per year at 13 hours/day for a utilization of 38.58 percent of the time, i.e.,

$$\frac{260 \text{ days/year} \times 13 \text{ hours/day}}{365 \text{ days/year} \times 24 \text{ hours/day}} = 0.3858 \text{ or } 38.58\%$$

1.11 Required Flue Gas Scrubber: Having ascertained the emission level limitation at the using location and the sulfur content of the cleaned coal, the minimum scrubber requirements necessary to meet such an emission standard can then be determined. The minimum scrubber requirements are determined as a function of the percent of flue gas which must be channeled through the flue gas desulfurization (FGD) system to meet the emission standard. This percentage is--

$$\frac{\% \text{ of flue gas cleaned}}{100} =$$

$$1 - \frac{\text{required emission standard}}{\frac{\text{emission from coal prior to FGD}}{\text{decimal operation efficiency of scrubber}}}$$

For this particular case the following applied:

$$\frac{\% \text{ of flue gas cleaned}}{100} = \frac{1 - \frac{1.2 \text{ lb. SO}_2/\text{MMBtu}}{1.43 \text{ lb. SO}_2/\text{MMBtu}}}{0.90}$$

$$\% \text{ of flue gas cleaned} = 17.8$$

This means that for our assumed plant site of 500 MW_e, 17.8 percent of the gas must be processed by the FGD system to meet standard. Therefore, minimum scrubber rating is--

$$0.178 \times 500 \text{ Mw} = 89 \text{ Mw}$$

In order to arrive at conservative design scrubber requirements for purposes of analysis, a 15-percent margin was allowed over the above value. Therefore, the scrubber design size in terms of MW_e flue gas treated is equal to:

$$89 \times 1.15 = 103 MW_e$$

The estimated scrubber capital cost is based on scaling factors derived in Section 5.1. Specifically, the estimated scrubber capital cost in millions of dollars is equal to:

$$\text{Cost} = \$73.573 \text{ MM} \left[\frac{\text{Capacity in } MW_e}{500} \right]^{0.79} \times [0.098 \times \%S + 0.657]$$

For this case this becomes:

$$\text{Cost} = \$73.573 \text{ MM} \left[\frac{103}{500} \right]^{0.79} \times [0.098 \times 0.94 + 0.657]$$

$$\text{Cost} = \$15,820,000$$

The scrubber annual charge factor for this case, as indicated in Section 5.2 is 17.85%. The scrubber annual charge per year is determined by multiplying the scrubber

capital cost by the annual charge factor expressed as a decimal. The annual charge is:

$$\$15.82 \text{ MM} \times 0.1785 = \$2.824 \text{ MM}$$

- 1.12 Flue Gas Reheat: The factors under this category are covered in Section 5.3.3 of text. The percent of total gas scrubbed is $103 \text{ MW}_e / 500 \text{ MW}_e \approx 0.21$ or 21%. According to Figure 12 reheat is not required. If all the flue gas would need to be scrubbed, the full scale reheat estimate is the 70 MMBtu hourly requirement (see Section 5.3.3) times the number of hours the plant operates a year (i.e., 7000 hours for case 5A). The yearly reheat cost for full reheat for a 500 MW_e plant when reheat energy cost \$2.00/MMBtu is merely the yearly reheat energy requirement times energy cost. For this case the yearly cost for full scale reheat (if required) is equal to:

$$70 \text{ MMBtu/hr} \times 7000 \text{ hrs/yr} \times \$2/\text{MMBtu} = \$980,000/\text{yr}.$$

It must be emphasized that reheat is not required for this case.

2.0 ECONOMIC ASSESSMENT

2.1 Coal Cleaning Cost per Ton of Cleaned Coal

- 2.1.1 Coal Cleaning Plant Cost: Cleaning plant amortization cost per ton of cleaned coal is equal to cleaning plant amortization cost per ton of raw coal input divided by the plant yield expressed as a decimal. For this case the plant cost \$20,000 per ton per hour input capacity and operates 3380 hours/year, interest on unpaid balance is 13.75 percent per year, loan period is 15 years years (i.e., 180 monthly payments) and the yearly payment amounts to \$3,155.97 per ton per hour input capacity. The cost attributable to a clean ton of coal is:

$$\frac{\$3,155.97}{3380 \times \text{wt.yield}} = \frac{\$3,155.97}{3380 \times 0.825} = \$1.13/\text{ton of clean coal}$$

The O&M cost (from Figure 5) is \$3.62 per ton clean coal.

- 2.1.2 Additional Coal Cost to Provide One Ton of Clean Coal: In the cleaning of coal, obviously more than 1 ton of raw coal must be processed in order to achieve 1 ton of clean coal. The amount of additional coal required depends on the level to which the coal is cleaned. From an economic standpoint, this additional increment of coal lost in the cleaning process represents a cost to the cleaning plant operator which must be considered. In the case of coal cleaning to 82.5 percent weight yield this cost is equal to:

$$\left(\frac{1}{0.825} - 1 \right) \times \text{mine operator's cost per ton of raw coal}$$

As indicated, for analysis purposes, a range of possible mine operator's cost per ton of raw coal was employed. This, in essence, would indicate the sensitivity of the overall economics to the value of mine operator places on the raw coal feed to the coal cleaning plant.

2.1.3 Cleaning Plant Tax & Insurance Burden: The cleaning plant tax and insurance estimate is covered in Section 3.5. The value for this case is \$0.22 per cleaned ton.

2.1.4 Total Cost Differential: The total differential (i.e., additional) cost to the mine operator to provide a ton of cleaned coal, when mine operator's coal cost is:

\$15.00/ton, differential cost is \$ 8.15
\$20.00/ton, differential cost is \$ 9.21
\$25.00/ton, differential cost is \$10.27

The above summarizes the cost values provided by items 2.1.1, 2.1.2, and 2.1.3 above.

2.2 Flue Gas Desulfurization Cost

2.2.1 Capital Contribution: The capital contribution (for FGD system) per ton of coal burned is simply the scrubber annual charge per year (see item 1.11) divided by the tons of coal burned per year (item 1.8) and is equal to \$2.12 per ton of coal burned.

2.2.2 FGD Electricity Cost: The FGD electricity cost, as based on a utility electric supply cost of 30 mills/kwh and Section 5.3.2 amounts to \$0.26 per ton of coal burned.

2.2.3 O & M Cost: The O&M cost is composed of the sum of four cost components: 1) raw material (i.e., limestone), 2) operating labor, 3) maintenance, and 4) other minor (i.e., miscellaneous) costs.

The limestone cost estimate, as based on Section 5.3.4 and limestone costing \$8 per ton, amounts to \$0.06 per ton of coal burned. The operating labor cost estimate as based on Section 5.3.5 equates to \$0.14 per ton of coal burned.

The total maintenance cost estimate (Section 5.3.6) per ton of coal burned equates to 4.6% of the FGD investment cost divided by the tons of coal burned per year. For this case, this equals:

$$\frac{\$15.82 \text{ MM} \times 0.046}{1.331 \text{ MM tons of coal per year}} = \$0.55 \text{ per ton of coal}$$

Miscellaneous charges per ton of coal burned are estimated to equal \$0.10 x decimal part of flue gas cleaned and equals \$0.02 for this example.

The total O&M cost is the sum of the above four cost components and equals \$0.77 per ton of coal.

2.2.4 Flue Gas Reheat Cost: Flue gas reheat cost per ton of coal burned is merely the full scale reheat cost (see item 1.12) times the decimal portion of the full scale reheat value (Section 5.3.3) all divided by the tons of coal burned per year (item 1.8). For this case, reheat is not required.

2.2.5 Total FGD Cost: The total FGD cost per ton of coal is simply the sum of items 2.2.1 through 2.2.4 above and equals \$3.15 per ton of coal burned.

2.3 Economic Benefits

2.3.1 Added Coal Value: There is added coal value due to the higher heat content of cleaned coal. When the f.o.b. mine raw coal price is:

\$30.00/ton, the added benefit is \$3.19/ton
\$40.00/ton, the added benefit is \$4.25/ton
\$50.00/ton, the added benefit is \$5.32/ton

When ash is removed from coal on cleaning, there is an increase in Btu content for the same unit weight. Since a buyer purchases Btu's and not tons the worth of a ton is greater. The quantification of this benefit (see Section 4.2) is:

$$\frac{\text{decimal Btu increase}}{1 + \text{decimal Btu increase}} \times \text{f.o.b. mine raw coal price}$$

For the purpose of the analysis, a reasonable range of possible f.o.b. mine raw coal prices per ton of cleaned coal was defined as based on publications by federal agencies, trade associations, industry newsletters, etc.

- 2.3.2 Effective Transportation Cost Saving: The effective transportation cost saving as based on the increased heat content of cleaned coal is covered by Section 4.3. The cost saving per ton of coal is:

$$\frac{\text{decimal Btu increase}}{1 + \text{decimal Btu increase}} \times \text{shipping cost per ton}$$

For this case, this amounts to \$0.98 per ton.

2.3.3 Ash Disposal Cost Saving: The saving in ash disposal cost is 1) due to the fact that cleaned coal contains less ash than the raw coal from which it was produced and 2) the clean coal has a higher Btu content (than the raw coal) and therefore fewer tons need be burned for a given heat requirement. The saving per ton of coal burned is quantified in Section 4.4 and is equal to:

$$(1 + \text{decimal increase in heat content per unit weight}) \times (\text{decimal reduction in ash content per unit weight}) \times (\text{the ash disposal cost per ton})$$

For this case, when the utility ash disposal cost is \$7.00 per ton (item 1.9), the saving amounts to \$0.72 per ton of coal.

2.3.4 Pulverizing Cost Saving: The saving in pulverizing cost is based on the fact that fewer tons of cleaned coal need be pulverized and burned for the same heat content as raw coal. The saving as based on Section 4.5 and a pulverizing cost of \$0.80 per ton amounts to \$0.09 per ton of coal burned.

2.3.5 Benefit Payment Saving: Saving in benefit payment (Section 4.6) is due to the fact that the contribution to the Miners' Pension & Benefit Trust Fund is based on coal shipped from a mine. Since the higher Btu content of cleaned coal requires the shipment of fewer tons for the same total Btu content, the saving in this area is:

$$\frac{\text{decimal Btu increase}}{1 + \text{decimal Btu increase}} \times \text{Trust Fund payment per ton}$$

On January 1, 1981, the payment amounted to \$1.385 for each ton of coal shipped to a consumer. The benefit payment saving for this case equates to \$0.15 per ton.

2.3.6 Maintenance Cost Saving: Saving in maintenance cost is addressed in Section 4.7. There is evidence that, for coals from the regions considered, there is a definite relationship between burning a reduced sulfur and ash coal and savings in maintenance cost at the coal burning facility. The saving of \$1.41 per ton is based on the saving versus ash and sulfur reduction relationship provided in Section 4.7.

2.3.7 Total Benefit per Ton of Clean Coal Burned: The total benefit per ton of cleaned coal burned, when the f.o.b. mine coal price is

\$30.00/ton, the total benefit is \$6.54/ton

\$40.00/ton, the total benefit is \$7.60/ton

\$50.00/ton, the total benefit is \$8.67/ton

The above summarized benefit values provided by items 2.3.1 through 2.3.6.

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

- 2.4.1 Net SO₂ Control Cost: Net SO₂ control cost is the coal cleaning cost plus FGD cost, less benefits from using cleaned coal. The cost is provided in terms of a) mine operator's raw coal cost (or value) and b) f.o.b. mine raw coal price. This readily shows sensitivity of overall economics to raw coal worth to the mining company and the cost to the utility user. The SO₂ control cost on a per ton burned basis are:

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (per ton)	\$15	4.76	3.70	2.63
	\$20	5.82	4.76	3.69
	\$25	6.88	5.82	4.75

The above is a composite of the differential cost to the mine operator to provide a ton of clean coal (item 2.1.4) plus the per ton FGD cost (item 2.2.5) less the per ton overall (non-environmental) economic benefit from burning cleaned coal.

- 2.4.2 SO₂ Control Cost per Million Btu's Burned: The SO₂ control cost per million Btu's burned is simply the above per ton values divided by the millions of Btu's per ton of cleaned coal.

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (per ton)	\$15	0.18	0.14	0.10
	\$20	0.22	0.18	0.14
	\$25	0.26	0.22	0.18

(Case 5A follows)

CASE NUMBER: 5A

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Grand Rapids, Michigan
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: West Virginia
County: Preston Coalbed: Upper Freeport
- 1.5 Raw Coal: 2.13XS, 17.6% Ash, 23.50 MMBtu/ton,
3.63 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 82.5% cleaning plant wt. yield,
92.3% cleaning plant Btu recovery, 26.30 MMBtu/ton,
0.94XS, 8.4% Ash, 1.43 lb. SO₂/MMBtu, 11.9% Btu increase
per unit wt. on cleaning.
- 1.7 Coal Transportation: 575 miles, \$9.20/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 25 yrs. remaining
life, 7000 hrs./year, 1.331 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity, utilized
260 days/ yr. @ 13 hrs./day (38.58% utilization), level
payment amortization
- 1.11 Flue Gas Scrubber: 89 MW_e minimum requirement, 103 MW_e
design size, \$MM 15.82 capital cost, 17.85 % annual cap.
chrg., \$MM 2.824 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 21% of flue gas scrubbed, 0% of full
scale reheat required, - MMBtu/yr. full reheat, \$ - /yr.
for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.13 for amortization, \$3.62 for
O&M

- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal. When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$3.18/ton
\$20.00/ton, additional coal cost is \$4.24/ton
\$25.00/ton, additional coal cost is \$5.30/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.22/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$8.15
\$20.00/ton, total additional cost is: \$9.21
\$25.00/ton, total additional cost is: \$10.27
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$ 2.12
- 2.2.2 Fuel & Electricity Cost: \$0.26
- 2.2.3 O&M Costs: \$0.06 raw materials (limestone), \$0.14 operating labor; \$0.55 maintenance; \$0.02 miscellaneous. Total O&M cost per ton of coal burned = \$0.77
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$ 3.15
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$3.19/ton
\$40.00/ton, added coal value is \$4.25/ton
\$50.00/ton, added coal value is \$5.32/ton
- 2.3.2 Transportation Cost Saving: \$0.98/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.72/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.09/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.15/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$1.41/ton

2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B. Mine Price is:

\$30.00/ton, the total benefit is \$6.54/ton

\$40.00/ton, the total benefit is \$7.60/ton

\$50.00/ton, the total benefit is \$8.67/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	4.76	3.70	2.63
	\$20	5.82	4.76	3.69
	\$25	6.88	5.82	4.75

2.4.2 Cost Per Million Btu Burned To Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.18	0.14	0.10
	\$20	0.22	0.18	0.14
	\$25	0.26	0.22	0.18

6.4 Summarization of Case Results

A total of 48 case analyses were performed. All of these cases are provided in their entirety as Appendix A hereto. Each case examines 1 of 12 selected coals and possible use areas from the standpoint of both a new and an existing plant utilizing either combined physical cleaning followed by stack gas scrubbing or sulfur dioxide cleanup exclusively by stack gas scrubbing. The cases are grouped according to coal and use area. This permits ease of comparison between like plants using the same coal in the same area but utilizing two different approaches to meeting existing or projected environmental standards. The emission standards used were identified as applicable as of January 1981.

Immediately following are summaries of each of the 48 case analyses. These summaries are grouped in sets for comparison of the costs associated with meeting emission standards from the two different approaches. For example, Cases 1A, 1B, 1C, and 1D are based on a coal coming from Sullivan County, Indiana, which is assumed being used in a utility plant in the Knoxville, Tennessee area. Cases 1A and 1B approach the analysis on the basis of an assumed new facility, whereas Case 1C and 1D assume an existing facility. However, Cases 1A and 1C address the analysis using a combination of physically cleaned coal followed by stack gas scrubbing, whereas Cases 1B and 1D approach the situation from the standpoint of using stack gas scrubbing alone. As can be readily seen from the summarization of these cases, the cost to meet the applicable sulfur emission standard is less in Cases 1A and 1C, which are the plants using combined physical and flue gas cleaning in new and existing facilities, respectively.

In each set of cases, the relative economic advantage (or disadvantage) is expressed as a percent for comparative purposes. The manner of stating economic advantage (less costly) or disadvantage (more costly) is dependent upon what, if any, action the coal-using plant has taken to meet environmental standards. For example, if, as in the case of 1C, the utility is using physically cleaned coal followed by FGD, then economic advantage could be stated as their cost is 27 percent less than by FGD alone. If, as in case 1D, the utility is using FGD alone, then economic disadvantage could be stated as their cost is 37 percent more than by the combined approach.

The summarization of case results referred to above follows:

SUMMARIZATION OF CASE RESULTS

CASE NUMBERS: 1A, 1B, 1C, and 1D

CASE CONDITIONS

Coal use area: Knoxville (Clinton), Tennessee

Coal source area: Sullivan County, Indiana

Coalbed: Number VII

Raw coal characteristics: 9.8 percent ash, 1.74 percent sulfur

Clean coal characteristics: 7.5 percent ash, 1.06 percent sulfur

CASE RESULTS

Case No.	Type of Plant and Approach	Emission Standard	Cost to Meet Emission Standard	Average Economic Advantage
<u>Comparison of Costs for New Plant</u>				
1 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO ₂ per MMBtu	\$0.31-0.35 per MMBtu	13 pct less than by FGD alone
1 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO ₂ per MMBtu	\$0.38 per MMBtu	15 pct more than by PC and FGD
<u>Comparison of Costs for Existing Plant</u>				
1 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO ₂ per MMBtu	\$0.47-0.51 per MMBtu	27 pct less than by FGD alone
1 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO ₂ per MMBtu	\$0.67 per MMBtu	37 pct more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 2A, 2B, 2C, and 2D

CASE CONDITIONS

Coal use area: Tonawanda (Buffalo), New York

Coal source area: Cambria County, Pennsylvania

Coalbed: Lower Freeport

Raw coal characteristics: 10.8 percent ash, 2.28 percent sulfur

Clean coal characteristics: 5.8 percent ash, 0.87 percent sulfur

CASE RESULTS

Case No.	Type of Plant and Approach	Emission Standard	Cost to Meet Emission Standard	Average Economic Advantage
<u>Comparison of Costs for New Plant</u>				
2 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO ₂ per MMBtu	\$0.08-0.20 per MMBtu	70 pct less than by FGD alone
2 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO ₂ per MMBtu	\$0.46 per MMBtu	229 pct more than by PC and FGD
<u>Comparison of Costs for Existing Plant</u>				
2 C	Existing plant with use of physical cleaning. FGD not required.	1.4 lb S per MMBtu	\$0.04-0.16 per MMBtu	68 pct less than by FGD alone
2 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.4 lb S per MMBtu	\$0.31 per MMBtu	210 pct more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 3A, 3B, 3C, and 3D

CASE CONDITIONS

Coal use area: Essexville (Saginaw), Michigan

Coal source area: Harrison County, Ohio

Coalbed: Lower Freeport

Raw coal characteristics: 9.8 percent ash, 2.17 percent sulfur

Clean coal characteristics: 3.9 percent ash, 1.03 percent sulfur

CASE RESULTS

Case No.	Type of Plant and Approach	Emission Standard	Cost to Meet Emission Standard	Average Economic Advantage
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Comparison of Costs for New Plant

3 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO ₂ per MMBtu	\$0.22-0.34 per MMBtu	36 pct less than by FGD alone
3 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO ₂ per MMBtu	\$0.44 per MMBtu	57 pct more than by PC and FGD

Comparison of Costs for Existing Plant

3 C	Existing plant with use of physical cleaning. FGD not required.	1.6 lb SO ₂ per MMBtu	\$0.07-0.18 per MMBtu	81 pct less than by FGD alone
3 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.6 lb SO ₂ per MMBtu	\$0.66 per MMBtu	428 pct more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 4A, 4B, 4C, and 4D

CASE CONDITIONS

Coal use area: Boston, Massachusetts

Coal source area: Clearfield County, Pennsylvania

Coalbed: Upper Kittanning

Raw coal characteristics: 8.7 percent ash, 0.83 percent sulfur

Clean coal characteristics: 7.2 percent ash, 0.46 percent sulfur

CASE RESULTS

Case No.	Type of Plant and Approach	Emission Standard	Cost to Meet Emission Standard	Average Economic Advantage
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Comparison of Costs for New Plant

4 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	0.28 lb S per MMBtu	\$0.26-0.30 per MMBtu	15 pct less than by FGD alone
4 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	0.28 lb S per MMBtu	\$0.33 per MMBtu	18 pct more than by PC and FGD

Comparison of Costs for Existing Plant

4 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	0.28 lb S per MMBtu	\$0.38-0.42 per MMBtu	32 pct less than by FGD alone
4 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	0.28 lb S per MMBtu	\$0.59 per MMBtu	48 pct more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 5A, 5B, 5C, and 5D

CASE CONDITIONS

Coal use area: Grand Rapids, Michigan

Coal source area: Preston County, West Virginia

Coalbed: Upper Freeport

Raw coal characteristics: 17.6 percent ash, 2.13 percent sulfur

Clean coal characteristics: 8.4 percent ash, 0.94 percent sulfur

CASE RESULTS

Case No.	Type of Plant and Approach	Emission Standard	Cost to Meet Emission Standard	Average Economic Advantage
<u>Comparison of Costs for New Plant</u>				
5 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO ₂ per MMBtu	\$0.10-0.26 per MMBtu	61 pct less than by FGD alone
5 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO ₂ per MMBtu	\$0.46 per MMBtu	156 pct more than by PC and FGD
<u>Comparison of Costs for Existing Plant</u>				
5 C	Existing plant with use of physical cleaning. FGD not required.	1.6 lb SO ₂ per MMBtu	\$(0.02)-0.14 per MMBtu	91 pct less than by FGD alone
5 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.6 lb SO ₂ per MMBtu	\$0.68 per MMBtu	1033 pct more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 6A, 6B, 6C, and 6D

CASE CONDITIONS

Coal use area: Springfield, Massachusetts

Coal source area: Armstrong County, Pennsylvania

Coalbed: Upper Freeport

Raw coal characteristics: 12.4 percent ash, 2.40 percent sulfur

Clean coal characteristics: 5.8 percent ash, 0.97 percent sulfur

CASE RESULTS

Case No.	Type of Plant and Approach	Emission Standard	Cost to Meet Emission Standard	Average Economic Advantage
<u>Comparison of Costs for New Plant</u>				
6 A	New plant with combined use of physical cleaning followed by stack gas	0.55 lb S per MMBtu	\$0.16-0.27 per MMBtu	56 pct less than by FGD alone
6 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	0.55 lb S per MMBtu	\$0.49 per MMBtu	128 pct more than by PC and FGD
<u>Comparison of Costs for Existing Plant</u>				
6 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	0.55 lb S per MMBtu	\$0.29-0.40 per MMBtu	60 pct less than by FGD alone
6 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	0.55 lb S per MMBtu	\$0.86 per MMBtu	149 pct more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 7A, 7B, 7C, and 7D

CASE CONDITIONS

Coal use area: Lansing, Michigan

Coal source area: Jefferson County, Ohio

Coalbed: Pittsburgh

Raw coal characteristics: 9.3 percent ash, 2.66 percent sulfur

Clean coal characteristics: 5.1 percent ash, 1.70 percent sulfur

CASE RESULTS

Case No.	Type of Plant and Approach	Emission Standard	Cost to Meet Emission Standard	Average Economic Advantage
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Comparison of Costs for New Plant

7 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO ₂ per MMBtu	\$0.47-0.58 per MMBtu	3 pct more than by FGD alone
7 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO ₂ per MMBtu	\$0.51 per MMBtu	3 pct less than by PC and FGD

Comparison of Costs for Existing Plant

7 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.6 lb SO ₂ per MMBtu	\$0.61-0.72 per MMBtu	15 pct less than by FGD alone
7 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.6 lb SO ₂ per MMBtu	\$0.78 per MMBtu	17 pct more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 8A, 8B, 8C, and 8D

CASE CONDITIONS

Coal use area: Nashville (Gallatin), Tennessee

Coal source area: Vigo County, Indiana

Coalbed: Number VII

Raw coal characteristics: 10.8 percent ash, 1.34 percent sulfur

Cleaned coal characteristics: 7.6 percent ash, 0.84 percent sulfur

CASE RESULTS

Case No.	Type of Plant and Approach	Emission Standard	Cost to meet Emission Standard	Average Economic Advantage
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Comparison of Costs for New Plant

8 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO ₂ per MMBtu	\$0.20-0.27 per MMBtu	24 pct less than by FGD alone
8 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO ₂ per MMBtu	\$0.31 per MMBtu	32 pct more than by PC and FGD

Comparison of Costs for Existing Plant

8 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO ₂ per MMBtu	\$0.29-0.36 per MMBtu	41 pct less than by FGD alone
8 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO ₂ per MMBtu	\$0.55 per MMBtu	69 pct more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 9A, 9B, 9C, and 9D

CASE CONDITIONS

Coal use area: Burlington, New Jersey

Coal source area: Garrett County, Maryland

Coalbed: Upper Freeport

Raw coal characteristics: 13.1 percent ash, 2.25 percent sulfur

Clean coal characteristics: 6.7 percent ash, 1.24 percent sulfur

CASE RESULTS

Case No.	Type of Plant and Approach	Emission Standard	Cost to Meet Emission Standard	Average Economic Advantage
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Comparison of Costs for New Plant

9 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	0.30 lb SO ₂ per MMBtu		This coal will not meet emission standards for new plants in the State of New Jersey even with combined physical and stack gas cleaning.
9 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	0.30 lb SO ₂ per MMBtu		This coal will not meet emission standards for new plants in the State of New Jersey using stack gas scrubbing.

Comparison of Costs for Existing Plant

9 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1 pct. S by weight (or equiv. emission)	\$0.35-0.50 per MMBtu	37 pct less than by FGD alone
9 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1 pct. S by weight (or equiv. emission)	\$0.68 per MMBtu	60 pct more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 10A, 10B, 10C, and 10D

CASE CONDITIONS

Coal use area: Milwaukee, Wisconsin

Coal source area: Franklin County, Illinois

Coalbed: Number 6

Raw coal characteristics: 13.7 percent ash, 1.09 percent sulfur

Clean coal characteristics: 6.4 percent ash, 0.94 percent sulfur

CASE RESULTS

Case No.	Type of Plant and Approach	Emission Standard	Cost to Meet Emission Standard	Average Economic Advantage
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Comparison of Costs for New Plant

10 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO ₂ per MMBtu	\$0.16-0.28 per MMBtu	8 pct less than by FGD alone
10 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO ₂ per MMBtu	\$0.24 per MMBtu	9 pct more than by PC and FGD

Comparison of Costs for Existing Plant

10 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO ₂ per MMBtu	\$0.27-0.39 per MMBtu	23 pct less than by FGD alone
10 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO ₂ per MMBtu	\$0.43 per MMBtu	30 pct more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 11A, 11B, 11C, and 11D

CASE CONDITIONS

Coal use area: Concord, New Hampshire

Coal source area: Greene County, Pennsylvania

Coalbed: Sewickley

Raw coal characteristics: 10.8 percent ash, 3.26 percent sulfur

Clean coal characteristics: 6.9 percent ash, 1.94 percent sulfur

CASE RESULTS

Case No.	Type of Plant and Approach	Emission Standard	Cost to Meet Emission Standard	Average Economic Advantage
<u>Comparison of Costs for New Plant</u>				
11 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO ₂ per MMBtu	\$0.51-0.62 per MMBtu	2 pct less than by FGD alone
11 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO ₂ per MMBtu	\$0.58 per MMBtu	3 pct more than by PC and FGD
<u>Comparison of Costs for Existing Plant</u>				
11 C	Existing plant with use of physical cleaning. FGD not required	1.5 lb S per MMBtu	\$0.12-0.23 per MMBtu	71 pct less than by FGD alone
11 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.5 lb S per MMBtu	\$0.60 per MMBtu	243 pct more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 12A, 12B, 12C, and 12D

CASE CONDITIONS

Coal use area: Dickerson (Montgomery County), Maryland

Coal source area: Marion County, West Virginia

Coalbed: Pittsburgh

Raw coal characteristics: 10.5 percent ash, 3.71 percent sulfur

Clean coal characteristics: 5.4 percent ash, 2.02 percent sulfur

CASE RESULTS

Case No.	Type of Plant and Approach	Emission Standard	Cost to Meet Emission Standard	Average Economic Advantage
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Comparison of Costs for New Plant

12 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO ₂ per MMBtu	\$0.43-0.53 per MMBtu	21 pct less than by FGD alone
12 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO ₂ per MMBtu	\$0.61 per MMBtu	27 pct more than by PC and FGD

Comparison of Costs for Existing Plant

12 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1 pct S by weight	\$0.65-0.74 per MMBtu	30 pct less than by FGD alone
12 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1 pct S by weight	\$1.00 per MMBtu	44 pct more than by PC and FGD

7.0 CONCLUSIONS

The economic analyses covering physical desulfurization of coal followed by flue gas desulfurization, and flue gas desulfurization used alone for selected coal source-user combinations indicate that economic generalizations must be approached with caution. The range of variability is such that each case must be individually assessed.

Available data indicate that many coals on appropriate physical cleaning will attain substantial reductions in ash and sulfur while retaining a high percentage of the coal's Btu content. These coals with reduced ash and sulfur contents are often not too far removed from the sulfur content level required to meet standards in some areas traditionally served by these coals.

When coal can be physically cleaned to a level not too far removed from that required to meet emission standards, flue gas desulfurization treating only a portion of the flue gas would satisfy environmental constraints. In many cases the net cost of physical desulfurization followed by flue gas desulfurization is substantially less than that of flue gas desulfurization alone. This is due to the net economics associated with physically cleaning coal combined with the substantially lower flue gas desulfurization costs. In essence, the net cost (i.e., costs less benefits) associated with physical desulfurization would be less than the additional cost if flue gas desulfurization was used alone.

For existing power plants, the real costs for flue gas desulfurization systems are especially expensive owing both to

higher capital costs and to the shorter economic lives of the systems. In many such cases, the use of physical desulfurization followed by flue gas desulfurization can be particularly attractive.

The provided case studies indicate that for many potential situations the economic advantage of a combined approach is quite significant. Key elements in economic advantage relate to (1) the availability of coals capable of significant reductions in ash and sulfur at reasonable Btu recovery levels, and (2) a beneficiated-coal sulfur level that is compatible with significantly less than full-scale scrubbing requirements. Even so, the range of variables is such that each source-user combination must be individually assessed. In this regard, it should be noted, the results can be weighted unrealistically to indicate excessively attractive economics by employing unrealistic factors (e.g., using shipping cost higher than warranted).

The previous assessment (Reference 2) indicated the potential attractiveness of coal cleaning combined with flue gas desulfurization. Since the initial study, substantial economic changes (e.g., cost of money) along with differential inflation values (i.e., by commodity) have occurred. In addition, data became available to permit quantifying an additional cost factor and to more precisely quantify other economic components. Due to the recent inflation history, the current study had to more fully address time/cost relationships.

The current assessments as based on current economic conditions and SO₂ emission standards imply that many of our medium- to high-sulfur content coals can be enhanced by cleaning to provide an assured supply of coal that could be used with flue

gas desulfurization to meet standards in a more economic fashion. This is true for many as-mined medium-sulfur content coals and some higher sulfur content coals that could serve areas with less restrictive environmental standards.

The overall study findings covering the combined use of physical cleaning followed by flue gas desulfurization indicate more dramatic savings than shown by the previous study (Reference 2). This effort indicated savings as high as 70 percent to an additional 3 percent cost as compared to flue gas desulfurization alone when applied to new steam coal utilities. The results are even more impressive for existing plants, where study assessments indicated a 15 percent to 91 percent savings for physical cleaning followed by flue gas desulfurization as compared with flue gas desulfurization alone.

It should be noted that a coal producer (depending on market and contract conditions) could raise the price of coal on cleaning beyond the additional cleaning cost which could include additional associated profit. Conceivably, coal cost could rise to the cost of coal associated with the SO_x emission control cost cross over point when comparing cleaned coal and flue gas desulfurization with unprepared coal and flue gas desulfurization.

There is an additional benefit derived from using cleaned coal that is not covered by this study. Many trace elements of concern are associated in total or part with the coal ash. When ash is removed, the emissions associated with these trace elements are reduced due to 1) removal of trace components on cleaning, and 2) the need to burn fewer tons of cleaned coal to meet a given heat content value since cleaning increases the per unit weight heat content of coal.

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APPENDIX A
CASE STUDIES



CASE NUMBERS: 1A, 1B, 1C, and 1D

Coal Source Area: Sullivan County, Indiana

Coal Use Area: Knoxville (Clinton), Tennessee

CASE NUMBER: 1A

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Knoxville (Clinton), Tennessee
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Indiana
County: Sullivan Coalbed: No. VII
- 1.5 Raw Coal: 1.74XS, 9.8% Ash, 24.07 MMBtu/ton,
2.89 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 95.0% cleaning plant wt. yield, 97.5%
cleaning plant Btu recovery, 24.70 MMBtu/ton, 1.06XS, 7.5%
Ash, 1.72 lb. SO₂/MMBtu, 2.6% Btu increase per unit wt. on
cleaning.
- 1.7 Coal Transportation: 454 miles, \$12.60/ton
- 1.8 Assumed Electric Utility Plant: 500 MWe, 25 yrs.
remaining life, 7000 hrs./year, 1.417 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity, utilized
260 days/ yr. @ 13 hrs./day (38.58% utilization), level payment
amortization
- 1.11 Flue Gas Scrubber: 168 MWe minimum requirement, 193 MWe
design size, \$MM 26.39 capital cost, 17.85 % annual cap.
chrg., \$MM 4.711 cap. chrg/yr.
- 1.12 Flue Gas Reheat: 39% of flue gas scrubbed, 0 % of full scale
reheat required, 0 MMBtu/yr. full reheat,
\$ - /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$0.98 for amortization,
\$3.13 for O&M

- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal. When Mine Operator's Coal Cost is:
 - \$15.00/ton, additional coal cost is \$0.79 /ton
 - \$20.00/ton, additional coal cost is \$1.05 /ton
 - \$25.00/ton, additional coal cost is \$1.32 /ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.19 /ton
- 2.1.4 Total Differential Cost of Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
 - \$15.00/ton, total additional cost is: \$ 5.09
 - \$20.00/ton, total additional cost is: \$ 5.35
 - \$25.00/ton, total additional cost is: \$ 5.62
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$3.32
- 2.2.2 Fuel & Electricity Cost: \$0.48
- 2.2.3 O&M Costs: \$0.12 raw materials (limestone), \$ 0.13 operating labor; \$0.87 maintenance; \$0.04 miscellaneous. Total O&M cost per ton of coal burned = \$1.16.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$4.96
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
 - \$30.00/ton, added coal value is \$0.77/ton
 - \$40.00/ton, added coal value is \$1.02/ton
 - \$50.00/ton, added coal value is \$1.28/ton
- 2.3.2 Transportation Cost Saving: \$0.32/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.17/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.02/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.04/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$0.54/ton

2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price is:

\$30.00/ton, the total benefit is \$1.86/ton

\$40.00/ton, the total benefit is \$2.11/ton

\$50.00/ton, the total benefit is \$2.37/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned to Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	8.19	7.94	7.68
of Raw Coal (Per Ton)	\$20	8.45	8.20	7.94
	\$25	8.72	8.47	8.21

2.4.2 Cost Per Million Btu Burned to Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	0.33	0.32	0.31
of Raw Coal (Per Ton)	\$20	0.34	0.33	0.32
	\$25	0.35	0.34	0.33

CASE NUMBER: 1B

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Knoxville (Clinton), Tennessee
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Indiana
County: Sullivan Coalbed: No. VII
- 1.5 Raw Coal:
1.74 %S 9.8% Ash 24.07 MMBtu/ton 2.89 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
25 years remaining life,
7000 hrs./year
1.454 MMtons/hr.
- 1.7 Flue Gas Scrubber:
325 MW_e minimum requirement,
374 MW_e design size, \$MM 48.40 capital cost,
17.85% annual cap. chrg., \$MM 8.639 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
75% of flue gas scrubbed,
17% of full scale reheat required,
490,000 MMBtu/yr. full reheat, \$980,000/yr. for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$5.94
- 2.2 Fuel & Electricity Cost: \$0.92
- 2.3 O&M Costs:
\$ 0.39 raw materials (limestone),
\$0.19 operating labor;

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\$1.53 maintenance;

\$0.08 miscellaneous.

Total O&M cost per ton of coal burned = \$ 2.19.

2.4 Flue Gas Reheat Cost: \$0.11

2.5 Total FGD Cost Per Ton of Coal: \$ 9.16

2.6 FGD Cost per MMBtu: \$0.38

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CASE NUMBER: 1C

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Knoxville (Clinton), Tennessee
- 1.2 Emission Standard: Existing Plant, 1.2 SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Indiana
County: Sullivan Coalbed: No. VII
- 1.5 Raw Coal: 1.74% S, 9.8% Ash, 24.07 MMBtu/ton,
2.89 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 95.0% cleaning plant wt. yield, 97.5% cleaning
plant Btu recovery, 24.70 MMBtu/ton, 1.06 %S, 7.5 % Ash, 1.72
lb. SO₂/MMBtu, 2.6% Btu increase per unit wt. on cleaning.
- 1.7 Coal Transportation: 454 miles, \$12.60/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 15 yrs. remaining
life, 5000 hrs./year, 1.012 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity, utilized
260 days/yr. @ 13 hrs./day (38.58% utilization), level payment
amortization
- 1.11 Flue Gas Scrubber: 168 MW_e minimum requirement, 193 MW_e design
size, \$MM 32.99 capital cost, 20.12% annual cap. chrg., \$MM
6.638 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 39% of flue gas scrubbed, 0% of full
scale reheat required, 0 MMBtu/yr. full reheat,
\$ - /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$0.98 for amortization,
\$3.13 for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal. When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$0.79/ton
\$20.00/ton, additional coal cost is \$1.05/ton
\$25.00/ton, additional coal cost is \$1.32/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.19/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$5.09
\$20.00/ton, total additional cost is: \$5.35
\$25.00/ton, total additional cost is: \$5.62
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$6.56
- 2.2.2 Fuel & Electricity Cost: \$0.48
- 2.2.3 O&M Costs: \$0.12 raw materials (limestone), \$ 0.18 operating labor; \$1.50 maintenance; \$0.04 miscellaneous. Total O&M cost per ton of coal burned = \$1.84.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$8.88
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$0.77/ton
\$40.00/ton, added coal value is \$1.02/ton
\$50.00/ton, added coal value is \$1.28/ton
- 2.3.2 Transportation Cost Saving: \$0.32/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.17/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.02/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.04/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$0.54/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B. Mine Price is:

\$30.00/ton, the total benefit is \$1.86/ton

\$40.00/ton, the total benefit is \$2.11/ton

\$50.00/ton, the total benefit is \$2.37/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned to Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	12.11	11.86	11.60
	\$20	12.37	12.12	11.86
	\$25	12.64	12.39	12.13

2.4.2 Cost Per Million Btu Burned To Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.49	0.48	0.47
	\$20	0.50	0.49	0.48
	\$25	0.51	0.50	0.49

CASE NUMBER: 1D

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Knoxville (Clinton), Tennessee
- 1.2 Emission Standard: Existing Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Indiana
County: Sullivan Coalbed: No. VII
- 1.5 Raw Coal:
1.74% S 9.8 % Ash 24.07 MMBtu/ton
2.89 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
15 yrs. remaining life,
5000 hrs./year,
1.039 MMtons/yr.
- 1.7 Flue Gas Scrubber:
325 MW_e minimum requirement,
374 MW_e design size, \$MM 60.50 capital cost,
20.12 % annual cap. chrg., \$MM 12.173 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
75% of flue gas scrubbed,
17% of full scale reheat required,
350,000 MMBtu/yr. full reheat, \$700,000/yr. for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$11.72
- 2.2 Fuel & Electricity Cost: 0.92
- 2.3 O&M Costs:
\$0.39 raw materials (limestone),
\$0.27 operating labor;

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\$2.68 maintenance;

\$0.08 miscellaneous.

Total O&M cost per ton of coal burned = \$3.42.

2.4 Flue Gas Reheat Cost: \$0.11

2.5 Total FGD Cost Per Ton of Coal: \$16.17

2.6 FGD Cost per MMBtu: \$0.67

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CASE NUMBERS: 2A, 2B, 2C, and 2D

Coal Source Area: Cambria County, Pennsylvania

Coal Use Area: Tonawanda (Buffalo), New York

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CASE NUMBER: 2A

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Tonawanda (Buffalo), New York
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Pennsylvania
County: Cambria Coalbed: Lower Freeport
- 1.5 Raw Coal: 2.28% S, 10.8% Ash, 25.82 MMBtu/ton,
3.53 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 85 % cleaning plant wt. yield, 92%
cleaning plant Btu recovery, 27.95 MMBtu/ton, 0.87% S,
5.8% Ash, 1.25 lb. SO₂/MMBtu, 8.2% BTU increase per
unit wt. on cleaning.
- 1.7 Coal Transportation: 300 miles, \$10.80/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 25 yrs.
remaining life, 7000 hrs./year, 1.252 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity,
utilized 260/days yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 22 MW_e minimum requirement, 26 MW_e design
size, \$MM 5.28 capital cost, 17.85% annual cap. chrg., \$MM
0.942 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 5% of flue gas scrubbed, 0% of full scale
reheat required, 0 MMBtu/yr. full reheat, \$ - /yr. for full
reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.10 for amortization,
\$3.51 for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal. When Mine Operator's Coal Cost is:
 - \$15.00/ton, additional coal cost is \$ 2.65/ton
 - \$20.00/ton, additional coal cost is \$ 3.53/ton
 - \$25.00/ton, additional coal cost is \$ 4.41/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.21/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
 - \$15.00/ton, total additional cost is: \$7.47
 - \$20.00/ton, total additional cost is: \$8.35
 - \$25.00/ton, total additional cost is: \$9.23
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
 - 2.2.1 Capital Contribution: \$ 0.75
 - 2.2.2 Fuel & Electricity Cost: \$0.06
 - 2.2.3 O&M Costs: \$0.01 raw materials (limestone), \$ 0.15 operating labor; \$ 0.19 maintenance; \$0.01 miscellaneous.
Total O&M cost per ton of coal burned = \$0.36.
 - 2.2.4 Flue Gas Reheat Cost: \$ -0-
 - 2.2.5 Total FGD Cost Per Ton of Coal: \$1.17
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
 - 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
 - \$30.00/ton, added coal value is \$2.28/ton
 - \$40.00/ton, added coal value is \$3.04/ton
 - \$50.00/ton, added coal value is \$3.80/ton
 - 2.3.2 Transportation Cost Saving: \$0.82/ton
 - 2.3.3 Saving in Utility Ash Disposal Cost: \$0.38/ton
 - 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.06/ton
 - 2.3.5 Saving in Pension Fund Payment: \$0.11/ton
 - 2.3.6 Saving in Utility Maintenance Cost: \$1.14/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B. Mine Price is:

\$30.00/ton, the total benefit is \$4.79/ton

\$40.00/ton, the total benefit is \$5.55/ton

\$50.00/ton, the total benefit is \$6.31/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned to Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	3.85	3.09	2.33
	\$20	4.73	3.97	3.21
	\$25	5.61	4.85	4.09

2.4.2 Cost Per Million Btu Burned To Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.14	0.11	0.08
	\$20	0.17	0.14	0.11
	\$25	0.20	0.17	0.15

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CASE NUMBER: 2B

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Tonawanda (Buffalo), New York
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Pennsylvania
County: Cambria Coalbed: Lower Freeport
- 1.5 Raw Coal:
2.28 %S 10.8 % Ash 25.82 MMBtu/ton 3.53 lb
SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e
25 yrs. remaining life
7000 hrs./year,
1.356 MMtons/yr.
- 1.7 Flue Gas Scrubber:
367 MW_e minimum requirement,
422 MW_e design size, \$MM capital cost,
17.85 % annual cap. chrg., \$MM 10.112 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
85% of flue gas scrubbed;
50% of full scale reheat required,
490,000 MMBtu/yr. full reheat, \$980,000/yr. for
full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$7.46
- 2.2 Fuel & Electricity Cost: \$1.04
- 2.3 O&M Costs:
\$0.58 raw materials (limestone)
\$0.21 operating labor;

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\$1.92 maintenance;

\$0.09 miscellaneous

Total O&M cost per ton of coal burned = \$2.80

2.4 Flue Gas Reheat Cost: \$0.36

2.5 Total FGD Cost Per Ton of Coal: \$11.66

2.6 FGD Cost per MMBtu: \$0.46

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CASE NUMBER: 2C

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Tonawanda (Buffalo), New York
- 1.2 Emission Standard: Existing Plant, 1.4 lb S per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Pennsylvania
County: Cambria Coalbed: Lower Freeport
- 1.5 Raw Coal: 2.28% S, 10.8% Ash, 25.82 MMBtu/ton,
3.53 lb SO₂/MMBtu
- 1.6 Cleaned Coal: 85% cleaning plant wt. yield, 92%
cleaning plant Btu recovery, 27.95 MMBtu/ton, 0.87% S,
5.8% Ash, 1.25 lb. SO₂/MMBtu,
8.2% Btu increase per unit wt. on cleaning.
- 1.7 Coal Transportation: 300 miles, \$10.80/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 15 yrs.
remaining life, 5000 hrs./year, 0.895 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr, input capacity,
utilized 260 days/yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 0 MW_e minimum requirement, 0 MW_e
design size, \$MM - capital cost, % annual
cap. chrg., \$MM cap. chrg./yr.
- 1.12 Flue Gas Reheat: 0 % of flue gas scrubbed, 0% of full
scale reheat required, MMBtu/yr. full reheat,
\$/yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.10 for amortization,
\$3.51 for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal. When Mine Operator's Coal Cost is:
 - \$15.00/ton, additional coal cost is \$ 2.65/ton
 - \$20.00/ton, additional coal cost is \$ 3.53/ton
 - \$25.00/ton, additional coal cost is \$ 4.41/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.21/ton
- 2.1.4 Total Differential Cost fo Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
 - \$15.00/ton, total additional cost is: \$ 7.47
 - \$20.00/ton, total additional cost is: \$8.35
 - \$25.00/ton, total additional cost is: \$9.23
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$ -0- (FGD not required)
- 2.2.2 Fuel & Electricity Cost: -0-
- 2.2.3 O&M Costs: \$ raw materials (limestone),
\$ operating labor; \$ maintenance,
\$ miscellaneous. Total O&M cost per ton
of coal burned = \$
- 2.2.4 Flue Gas Reheat Cost: \$
- 2.2.5 Total FGD Cost Per Ton of Coal: \$
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
 - \$30.00/ton, added coal value is \$2.28/ton
 - \$40.00/ton, added coal value is \$3.04/ton
 - \$50.00/ton, added coal value is \$3.80/ton
- 2.3.2 Transportation Cost Saving: \$0.82/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.38/ton
- 2.3.4 Saving in Pension Fund Payment: \$0.06/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.11/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$1.14/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price is:

\$30.00/ton, the total benefit is \$4.79/ton

\$40.00/ton, the total benefit is \$5.55/ton

\$50.00/ton, the total benefit is \$6.31/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	2.68	1.92	1.16
of Raw Coal (Per Ton)	\$20	3.56	2.80	2.04
	\$25	4.44	3.68	2.92

2.4.2 Cost Per Million Btu Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	0.10	0.07	0.04
of Raw Coal (Per Ton)	\$20	0.13	0.10	0.09
	\$25	0.16	0.13	0.10

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CASE NUMBER: 2D

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Tonawanda (Buffalo), New York
- 1.2 Emission Standard: Existing Plant, 1.4 lb S per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Pennsylvania
County: Cambria Coalbed: Lower Freeport
- 1.5 Raw Coal:
2.28% S 10.8% Ash 25.82 MMBtu/ton
3.53 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e
15 yrs. remaining life,
5000 hrs./year,
0.968 MMtons/yr.
- 1.7 Flue Gas Scrubber:
115 MW_e minimum requirement,
132 MW_e design size, \$MM 28.27 capital cost,
20.12% annual cap. chrg., \$MM 5.688 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
27 % of flue gas scrubbed,
0 % of full scale reheat required,
MMBtu/yr. full reheat, \$ - /yr. for
full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$5.88
- 2.2 Fuel & Electricity Cost: \$0.33
- 2.3 O&M Costs: \$
\$0.18 raw materials (limestone),
\$0.19 operating labor;

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\$1.34 maintenance;

\$0.03 miscellaneous.

Total O&M cost per ton of coal burned = \$1.74

2.4 Flue Gas Reheat Cost: \$ -0-

2.5 Total FGD Cost Per Ton of Coal: \$7.95

2.6 FGD cost per MMBtu: \$0.31

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CASE NUMBERS: 3A, 3B, 3C, and 3D
Coal Source Area: Harrison County, Ohio
Coal Use Area: Essexville (Saginaw), Michigan

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CASE NUMBER: 3A

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Essexville (Saginaw), Michigan
- 1.2 Emission Standard: New Plant, 1.2 lb, SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Ohio
County: Harrison Coalbed: Lower Freeport
- 1.5 Raw Coal: 2.17% S, 9.8% Ash, 25.01 MMBtu/ton,
3.48 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 85% cleaning plant wt. yield, 91%
cleaning plant Btu recovery, 26.78 MMBtu/ton,
1.03% S, 3.9% Ash, 1.54 lb. SO₂/MMBtu,
7.06% Btu increase per unit wt. on cleaning.
- 1.7 Coal Transportation: 375 miles, \$10.52/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 25 yrs.
remaining life, 7000 hrs./year, 1.307 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity,
utilized 260 days/yr. @ 13 hrs./day (38.58%
utilization), level payment amortization
- 1.11 Flue Gas Scrubber: 123 MW_e minimum requirement, 141 MW_e
design size, \$MM 20.51 capital cost, 17.85% annual
cap. chrg., \$MM 3.661 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 28% of flue gas scrubbed, 0% of full
scale reheat required, - MMBtu/ yr. full reheat,
\$ - /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.10 for amortization, \$3.51
for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$2.65/ton
\$20.00/ton, additional coal cost is \$3.53/ton
\$25.00/ton, additional cost cost is \$4.41/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.21/ton
- 2.1.4 Total Differential Cost of Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$7.47
\$20.00/ton, total additional cost is: \$8.35
\$25.00/ton, total additional cost is: \$9.23
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$2.80
- 2.2.2 Fuel & Electricity Cost: \$0.34
- 2.2.3 O&M Costs: \$0.09 raw materials (limestone), \$0.14 operating labor; \$0.72 maintenance; \$0.03 miscellaneous. Total O&M cost per ton of coal burned = \$0.98.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$4.12
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$1.98/ton
\$40.00/ton, added coal value is \$2.64/ton
\$50.00/ton, added coal value is \$3.30/ton
- 2.3.2 Transportation Cost Saving: \$0.69/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.45/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.05/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.09/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$1.10/ton

2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price is:

\$30.00/ton, the total benefit is \$4.36/ton

\$40.00/ton, the total benefit is \$5.02/ton

\$50.00/ton, the total benefit is \$5.68/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	7.23	6.57	5.91
	\$20	8.11	7.45	6.79
	\$25	8.99	8.33	7.67

2.4.2 Cost Per Million Btu Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.27	0.24	0.22
	\$20	0.30	0.28	0.25
	\$25	0.34	0.31	0.29

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CASE NUMBER: 3B

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Essexville (Saginaw), Michigan
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Ohio
County: Harrison Coalbed: Lower Freeport
- 1.5 Raw Coal:
2.17 %S 9.8% Ash 25.01 MMBtu/ton
3.48 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
25 yrs. remaining life,
7000 hrs./year,
1.399 MMtons/yr.
- 1.7 Flue Gas Scrubber:
364 MW_e minimum requirement,
419 MW_e design size, \$MM 55.67 capital cost,
17.85 % annual cap. chrg., \$MM 9.937 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
84% of flue gas scrubbed,
47% of full scale reheat required,
490,000 MMBtu/yr. full reheat, \$980,000/yr. for
full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$7.19
- 2.2 Fuel & Electricity Cost: \$1.02
- 2.3 O&M Costs:
\$0.55 raw materials (limestone),
\$0.20 operating labor;

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\$1.83 maintenance;

\$0.08 miscellaneous.

Total O&M cost per ton of coal burned = \$2.66

2.4 Flue Gas Reheat Cost: \$0.33

2.5 Total FGD Cost Per Ton of Coal: \$11.11

2.6 FGD Cost per MMBtu: \$0.44

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CASE NUMBER: 3C

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Essexville (Saginaw), Michigan
- 1.2 Emission Standard: Existing Plant, 1.6 lb SO₂ MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Ohio
County: Harrison Coalbed: Lower Freeport
- 1.5 Raw Coal: 2.17 %S, 9.8% Ash, 25.01 MMBtu/ton,
3.48 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 85% cleaning plant wt. yield,
91% cleaning plant Btu recovery, 26.78 MMBtu/ton,
1.03 %S, 3.9% Ash, 1.54 lb. SO₂/MMBtu, 7.06 % Btu
increase per unit wt. on cleaning.
- 1.7 Coal Transportation: miles, \$ /ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 15 yrs.
remaining life, 5000 hrs./year, 0.9336 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity,
utilized 260 days/ yr. @ 13 hrs./day (38.58%
utilization), level payment amortization
- 1.11 Flue Gas Scrubber: 0 MW_e minimum requirements, 0 MW_e
design size, \$MM - capital cost, - % annual
cap. chrg., \$MM cap. chrg./yr.
- 1.12 Flue Gas Reheat: 0 % of flue gas scrubbed, 0 % of
full scale reheat required, - MMBtu/yr. full reheat,
\$ - /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.10 for amortization, \$3.51
for O&M
- 2.1.2 Additional Coal Cost to Provide One Ton of
Cleaned Coal. When Mine Operator's Coal Cost is:

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- \$15.00/ton, additional coal cost is \$2.65/ton
\$20.00/ton, additional coal cost is \$3.53/ton
\$25.00/ton, additional coal cost is \$4.41/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.21/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One
Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$7.47
\$20.00/ton, total additional cost is \$8.35
\$25.00/ton, total additional cost is: \$9.23
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$ -0- (FGD not required)
- 2.2.2 Fuel & Electricity Cost:
- 2.2.3 O&M Costs: \$ raw materials (limestone), \$ operating
labor; \$ maintenance; \$ miscellaneous. Total
O&M cost per ton of coal burned = \$
- 2.2.4 Flue Gas Reheat Cost: \$
- 2.2.5 Total FGD Cost Per Ton of Coal: \$0
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher
Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$1.98/ton
\$40.00/ton, added coal value is \$2.64/ton
\$50.00/ton, added coal value is \$3.30/ton
- 2.3.2 Transportation Cost Saving: \$0.69/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.45/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.05/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.09/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$1.10/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B. Mine Price is:

\$30.00/ton, the total benefit is \$4.36/ton

\$40.00/ton, the total benefit is \$5.02/ton

\$50.00/ton, the total benefit is \$5.68/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	3.11	2.45	1.79
of Raw Coal (Per Ton)	\$20	3.99	3.33	2.67
	\$25	4.87	4.21	3.55

2.4.2 Cost Per Million Btu Burned To Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator' Cost	\$15	0.12	0.09	0.07
of Raw Coal (Per Ton)	\$20	0.15	0.12	0.10
	\$25	0.18	0.16	0.13

CASE NUMBER: 3D

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Essexville (Saginaw), Michigan
- 1.2 Emission Standard: Existing Plant, 1.6 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Ohio
County: Harrison Coalbed: Lower Freeport
- 1.5 Raw Coal:
2.17% S 9.8% Ash 25.01 MMBtu/ton
3.48 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
15 yrs. remaining life,
5000 hrs./year,
1.000 MMtons/yr.
- 1.7 Flue Gas Scrubber:
300 MW_e minimum requirement
345 MW_e design size, \$MM 59.68 capital cost,
20.12 % annual cap. chrg., \$MM 12.008 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
69% of flue gas scrubbed,
-0-% of full scale reheat required,
MMBtu/yr. full reheat, \$ /yr. for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$12.01
- 2.2 Fuel & Electricity Cost: \$0.84
- 2.3 O&M Costs:
\$0.45 raw materials (limestone),
\$0.28 operating labor;

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\$2.75 maintenance;

\$0.07 miscellaneous.

Total O&M cost per ton of coal burned = \$3.55.

2.4 Flue Gas Reheat Cost: \$ -0-

2.5 Total FGD Cost Per Ton of Coal: \$16.40

2.6 FGD Cost per MMBtu: \$0.66



CASE NUMBERS: 4A, 4B, 4C, and 4D

Coal Source Area: Clearfield County, Pennsylvania

Coal Use Area: Boston, Massachusetts

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CASE NUMBER: 4A

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Boston, Massachusetts
- 1.2 Emission Standard: New Plant, 0.28 lb S per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Pennsylvania
County: Clearfield Coalbed: Upper Kittaning
- 1.5 Raw Coal: 0.83 %S, 8.65% Ash, 25.05 MMBtu/ton,
1.33 lb SO₂/MMBtu
- 1.6 Cleaned Coal: 95.7% cleaning plant wt. yield,
97.5% cleaning plant Btu recovery, 25.52 MMBtu/ton,
0.46%S, 7.2% Ash, 0.72 lb. SO₂/MMBtu, 1.9% Btu increase
per unit wt. on cleaning.
- 1.7 Coal Transportation: 551 miles, \$14.88/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 25 yrs.
remaining life, 7000 hrs./year, 1.3714 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$17,150/ton/hr. input capacity,
utilized 260 days/ yr. @ 13 hrs./day (38.58%
utilization), level payment amortization
- 1.11 Flue Gas Scrubber: 124 MW_e minimum requirement,
143 MW_e design size, \$MM 19.21 capital cost, 17.85%
annual cap. chrg., \$MM 3.429 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 29% of flue gas scrubbed, 0% of
full scale reheat required, - MMBtu/yr. full reheat,
\$ - /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$0.84 for amortization,
\$3.12 for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal. When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$0.67/ton
\$20.00/ton, additional coal cost is \$0.90/ton
\$25.00/ton, additional coal cost is \$1.12/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.16/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$4.79
\$20.00/ton, total additional cost is: \$5.02
\$25.00/ton, total additional cost is: \$5.24
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$2.50
- 2.2.2 Fuel & Electricity Cost: \$0.85
- 2.2.3 O&M Costs: \$0.04 raw materials (limestone), \$0.14 operating labor; \$0.64 maintenance; \$0.03 miscellaneous. Total O&M cost per ton of coal burned = \$0.85.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$3.70
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$0.56/ton
\$40.00/ton, added coal value is \$0.75/ton
\$50.00/ton, added coal value is \$0.93/ton
- 2.3.2 Transportation Cost Saving: \$0.28/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.10/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.01/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.03/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$0.31/ton

2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B. Mine Price is:

\$30.00/ton, the total benefit is \$1.29/ton

\$40.00/ton, the total benefit is \$1.48/ton

\$50.00/ton, the total benefit is \$1.66/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	7.20	7.01	6.83
of Raw Coal (Per Ton)	\$20	7.43	7.24	7.06
	\$25	7.65	7.46	7.28

2.4.2 Cost Per Million Btu Burned To Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	0.28	0.27	0.26
of Raw Coal (Per Ton)	\$20	0.29	0.28	0.28
	\$25	0.30	0.29	0.29

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CASE NUMBER: 4B

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Boston, Massachusetts
- 1.2 Emission Standard: New Plant, 0.28 lb S per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Pennsylvania
County: Clearfield Coalbed: Upper Kittanning
- 1.5 Raw Coal:
083XS 8.65% Ash 25.05 MMBtu/ton
1.33 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
25 yrs. remaining life,
7000 hrs./year,
1.397 MMtons/yr.
- 1.7 Flue Gas Scrubber:
321 MW_e minimum requirement,
369 MW_e design size, \$MM 42.73 capital cost,
17.85 % annual cap. chrg., \$MM 7.627 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
74% of flue gas scrubbed,
14% of full scale reheat required,
490,000 MMBtu/yr. full reheat, \$980,000/yr. for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$5.46
- 2.2 Fuel & Electricity Cost: \$0.90
- 2.3 O&M Costs:
\$0.18 raw materials (limestone),
\$0.20 operating labor;

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\$1.41 maintenance;

\$0.07 miscellaneous.

Total O&M cost per ton of coal burned = \$1.86.

2.4 Flue Gas Reheat Cost: \$0.10

2.5 Total FGD Cost Per Ton of Coal: \$8.32

2.6 FGD Cost per MMBtu: \$0.33

CASE NUMBER: 4C

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Boston, Massachusetts
- 1.2 Emission Standard: Existing Plant, 0.28 lb S per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Pennsylvania
County: Clearfield Coalbed: Upper Kittaning
- 1.5 Raw Coal: 0.83% S, 8.65% Ash, 25.05 MMBtu/ton,
1.33 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 95.7% cleaning plant wt. yield,
97.5% cleaning plant Btu recovery, 25.52 MMBtu/ton,
0.46% S, 7.2% Ash, 0.72 lb. SO₂ MMBtu, 1.9 % Btu
increase per unit wt. on cleaning.
- 1.7 Coal Transportation: 551 miles, \$14.88/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 15 yrs.
remaining life, 5000 hrs./year, 0.9795 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$17,150/ton/hr. input capacity,
utilized 260 days/ yr. @ 13 hrs./day (38.58%
utilization), level payment amortization
- 1.11 Flue Gas Scrubber: 124 MW_e minimum requirement, 143
MW_e design size, \$MM 24.02 capital cost, 20.12 %
annual cap. chrg., \$MM 4.833 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 29% of flue gas scrubbed, 0 % of full
scale reheat required, - MMBtu/yr. full reheat
\$ - /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$0.84 for amortization,
\$3.12 for O&M

- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal. When Mine Operator's Coal Cost is:
 - \$15.00/ton, additional coal cost is \$0.67/ton
 - \$20.00/ton, additional coal cost is \$0.90/ton
 - \$25.00/ton, additional coal cost is \$1.12/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.16/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
 - \$15.00/ton, total additional cost is: \$4.79
 - \$20.00/ton, total additional cost is: \$5.02
 - \$25.00/ton, total additional cost is: \$5.24
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$4.93
- 2.2.2 Fuel & Electricity Cost: 0.35
- 2.2.3 O&M Cost: \$0.04 raw materials (limestone), \$0.19 operating labor; \$1.13 maintenance; \$0.03 miscellaneous. Total O&M cost per ton of coal burned = \$1.39.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$6.67
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
 - \$30.00/ton, added coal value is \$0.55/ton
 - \$40.00/ton, added coal value is \$0.75/ton
 - \$50.00/ton, added coal value is \$0.93/ton
- 2.3.2 Transportation Cost Saving: \$0.28/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.10/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.01/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.03/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$0.31/ton

2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price is:

\$30.00/ton, the total benefit is \$1.28/ton

\$40.00/ton, the total benefit is \$1.48/ton

\$50.00/ton, the total benefit is \$1.66/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission Standard:

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	10.18	9.98	9.80
of Raw Coal (Per Ton)	\$20	10.41	10.21	10.03
	\$25	10.63	10.43	10.25

2.4.2 Cost Per Million Btu Burned To Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	0.40	0.39	0.38
of Raw Coal (Per Ton)	\$20	0.41	0.40	0.39
	\$25	0.42	0.41	0.40

CASE NUMBER: 4D

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Boston, Massachusetts
- 1.2 Emission Standard: Existing Plant, 0.28 lb S per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Pennsylvania
County: Clearfield Coalbed: Upper Kittanning
- 1.5 Raw Coal:
0.83% S 8.65% Ash 25.05 MMBtu/ton
1.33 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
15 yrs. remaining life,
5000 hrs./year,
0.998 MMtons/yr.
- 1.7 Flue Gas Scrubber:
321 MW_e minimum requirement,
369 MW_e design size, \$MM 53.41 capital cost,
20.12 % annual cap. chrg., \$MM 10.746 cap.chrg./yr.
- 1.8 Flue Gas Reheat:
74% of flue gas scrubbed,
14% of full scale reheat required,
350,000 MMBtu/yr. full reheat, \$700,000/yr. for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$10.77
- 2.2 Fuel & Electricity Cost: \$0.90
- 2.3 O&M Costs:
\$0.18 raw materials (limestone),
\$0.28 operating labor;

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\$2.46 maintenance;

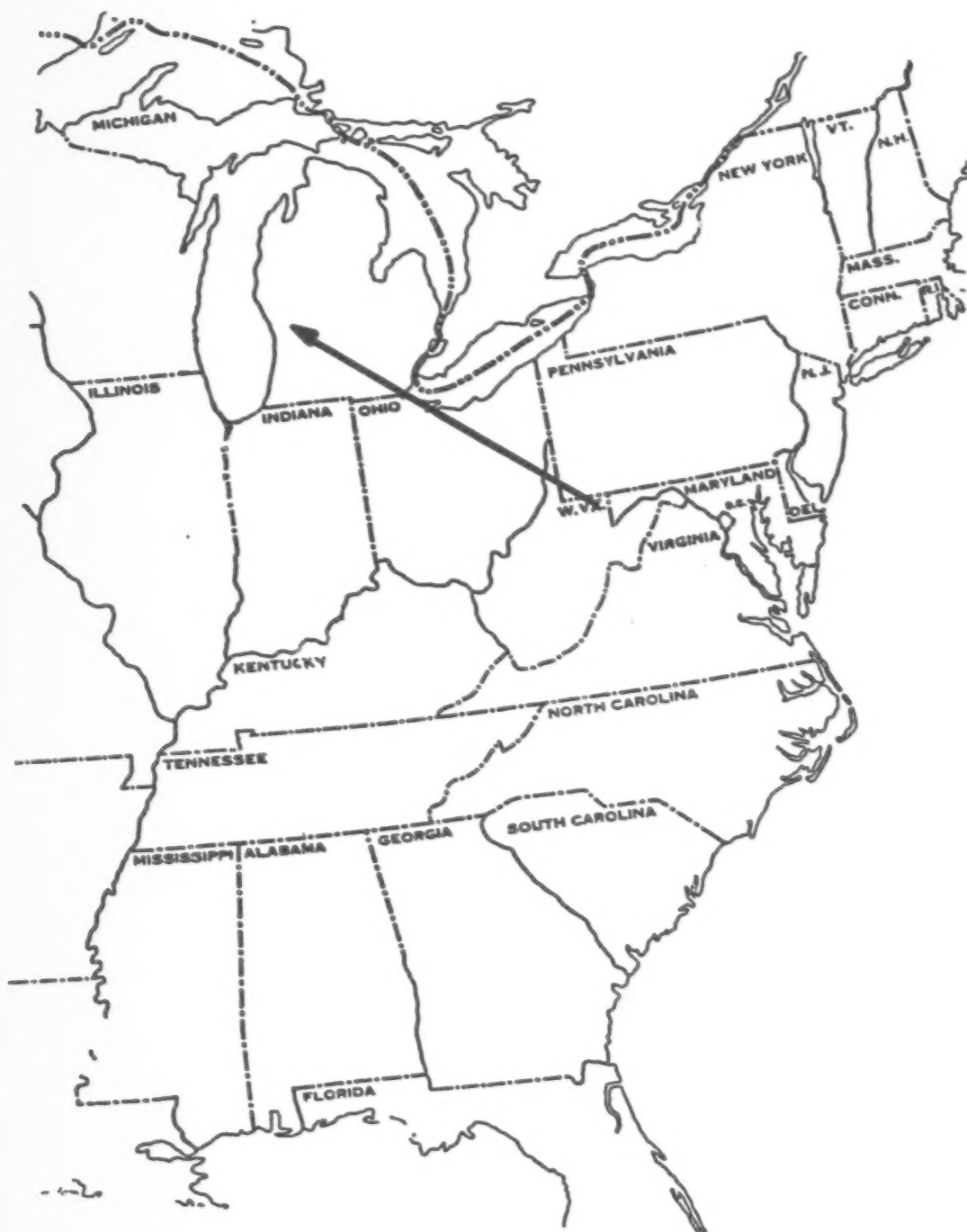
\$0.07 miscellaneous.

Total O&M cost per ton of coal burned = \$2.99

2.4 Flue Gas Reheat Cost: \$0.10

2.5 Total FGD Cost Per Ton of Coal: \$14.76

2.6 FGD Cost per MMBtu: \$0.59



CASE NUMBERS: 5A, 5B, 5C, and 5D
Coal Source Area: Preston County, West Virginia
Coal Use Area: Grand Rapids, Michigan

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CASE NUMBER: 5A

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Grand Rapids, Michigan
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: West Virginia
County: Preston Coalbed: Upper Freeport
- 1.5 Raw Coal: 2.13% S, 17.6% Ash, 23.50 MMBtu/ton,
3.63 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 82.5% cleaning plant wt. yield,
92.3% cleaning plant Btu recovery, 26.30 MMBtu/ton,
0.94% S, 8.4% Ash, 1.43 lb. SO₂/MMBtu, 11.9% Btu increase
per unit wt. on cleaning.
- 1.7 Coal Transportation: 575 miles, \$9.20/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 25 yrs. remaining
life, 7000 hrs./year, 1.331 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity, utilized
260 days/ yr. @ 13 hrs./day (38.58% utilization), level
payment amortization
- 1.11 Flue Gas Scrubber: 89 MW_e minimum requirement, 103 MW_e
design size, \$MM 15.82 capital cost, 17.85 % annual cap.
chrg., \$MM 2.824 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 21% of flue gas scrubbed, 0% of full
scale reheat required, - MMBtu/yr. full reheat, \$ - /yr.
for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.13 for amortization, \$3.62 for
O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal. When Mine Operator's Coal Cost is:
 - \$15.00/ton, additional coal cost is \$3.18/ton
 - \$20.00/ton, additional coal cost is \$4.24/ton
 - \$25.00/ton, additional coal cost is \$5.30/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.22/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
 - \$15.00/ton, total additional cost is: \$8.15
 - \$20.00/ton, total additional cost is: \$9.21
 - \$25.00/ton, total additional cost is: \$10.27
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$ 2.12
- 2.2.2 Fuel & Electricity Cost: \$0.26
- 2.2.3 O&M Costs: \$0.06 raw materials (limestone), \$0.14 operating labor; \$0.55 maintenance; \$0.02 miscellaneous. Total O&M cost per ton of coal burned = \$0.77
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$ 3.15
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
 - \$30.00/ton, added coal value is \$3.19/ton
 - \$40.00/ton, added coal value is \$4.25/ton
 - \$50.00/ton, added coal value is \$5.32/ton
- 2.3.2 Transportation Cost Saving: \$0.98/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.72/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.09/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.15/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$1.41/ton

2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B. Mine Price is:

\$30.00/ton, the total benefit is \$6.54/ton

\$40.00/ton, the total benefit is \$7.60/ton

\$50.00/ton, the total benefit is \$8.67/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	4.76	3.70	2.63
	\$20	5.82	4.76	3.69
	\$25	6.88	5.82	4.75

2.4.2 Cost Per Million Btu Burned To Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.18	0.14	0.10
	\$20	0.22	0.18	0.14
	\$25	0.26	0.22	0.18

CASE NUMBER: 5B

1.0 CASE CONDITIONS

1.1 Coal Use Area: Grand Rapids, Michigan

1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu

1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)

1.4 Origin of Coal: State: West Virginia

County: Preston Coalbed: Upper Freeport

1.5 Raw Coal:

2.13% S 17.6% Ash 23.50 MMBtu/ton

3.63 lb SO₂/MMBtu

1.6 Assumed Electric Utility Plant: 500 MW_e,

25 yrs. remaining life,

7000 hrs./year,

1.4894 MMtons/yr.

1.7 Flue Gas Scrubber:

372 MW_e minimum requirement,

428 MW_e design size, \$MM 56.33 capital cost,

17.85% annual cap. chrg., \$MM 10.055 cap. chrg./yr.

1.8 Flue Gas Reheat:

86% of flue gas scrubbed,

54% of full scale reheat required,

490,000 MMBtu/yr. full reheat, \$980,000/yr. for full reheat.

2.0 FGD COSTS PER TON OF CLEANED COAL BURNED

2.1 Capital Contribution: \$6.75

2.2 Fuel & Electricity Cost: \$1.05

2.3 O&M Costs:

\$0.55 raw materials (limestone),

\$0.19 operating labor;

\$1.74 maintenance;

\$0.09 miscellaneous.

Total O&M cost per ton of coal burned = \$2.57.

2.4 Flue Gas Reheat Cost: \$ 0.36

2.5 Total FGD Cost Per Ton of Coal: \$10.73

2.6 FGD Cost per MMBtu: \$0.46

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CASE NUMBER: 5C

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Grand Rapids, Michigan
- 1.2 Emission Standard: Existing Plant, 1.6 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: West Virginia
County: Preston Coalbed: Upper Freeport
- 1.5 Raw Coal: 2.13% S, 17.6% Ash, 23.50 MMBtu/ton,
3.63 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 82.5% cleaning plant wt. yield, % cleaning
plant Btu recovery, 26.30 MMBtu/ton, 0.94% S,
8.4% Ash, 1.43 lb. SO₂/MMBtu, 11.9% Btu increase per unit
wt. on cleaning.
- 1.7 Coal Transportation: 575 miles, \$9.20/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 15 yrs. remaining
life, 5000 hrs./year, 0.9506 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity,
utilized 260 days/ yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 0 MW_e minimum requirement, MW_e design
size, \$MM - capital cost, - % annual cap. chrg.,
\$MM cap. chrg./yr.
- 1.12 Flue Gas Reheat: 0 % of flue gas scrubbed, 0% of full
scale reheat required, MMBtu/yr. full reheat, \$ /yr.
for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.13 for amortization, \$3.62
for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal. When Mine Operator's Coal Cost is:
 \$15.00/ton, additional coal cost is \$3.18/ton
 \$20.00/ton, additional coal cost is \$4.24/ton
 \$25.00/ton, additional coal cost is \$5.30/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.22/ton
- 2.1.4 Total Differential Cost of Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
 \$15.00/ton, total additional cost is: \$8.15
 \$20.00/ton, total additional cost is: \$9.21
 \$25.00/ton, total additional cost is: \$10.27
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$ 0 (FGD not required)
- 2.2.2 Fuel & Electricity Cost:
- 2.2.3 O&M Costs: \$ raw materials (limestone), \$ operating labor; \$ maintenance; \$ miscellaneous. Total O&M cost per ton of coal burned = \$
- 2.2.4 Flue Gas Reheat Cost: \$ 0
- 2.2.5 Total FGD Cost Per Ton of Coal: \$
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
 \$30.00/ton, added coal value is \$3.19/ton
 \$40.00/ton, added coal value is \$4.25/ton
 \$50.00/ton, added coal value is \$5.32/ton
- 2.3.2 Transportation Cost Saving: \$0.98/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.72/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.09/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.15/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$1.41/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B. Mine Price is:

\$30.00/ton, the total benefit is \$6.54/ton

\$40.00/ton, the total benefit is \$7.60/ton

\$50.00/ton, the total benefit is \$8.67/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	1.61	0.55	-0.52
of Raw Coal (Per Ton)	\$20	2.67	1.61	0.54
	\$25	3.73	2.67	1.60

2.4.2 Cost Per Million Btu Burned To Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	0.06	0.02	-0.02
of Raw Coal (Per Ton)	\$20	0.10	0.06	-0.02
	\$25	0.14	0.10	0.06

CASE NUMBER: 5D

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Grand Rapids, Michigan
- 1.2 Emission Standard: Existing Plant, 1.6 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: West Virginia
County: Freston Coalbed: Upper Freeport
- 1.5 Raw Coal:
2.13 %S 17.6 % Ash 23.50 MMBtu/ton
3.63 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e
15 yrs. remaining life,
5000 hrs./year,
1.0638 MMtons/yr.
- 1.7 Flue Gas Scrubber:
311 MW_e minimum requirement,
357 MW_e design size, \$MM 61.02 capital cost,
20.12 % annual cap. chrg., \$MM 12.177 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
72% of flue gas scrubbed,
7% of full scale reheat required,
350,000 MMBtu/yr. full reheat, \$700,000/yr. for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$11.54
- 2.2 Fuel & Electricity Cost: \$0.88
- 2.3 O&M Costs:
\$0.46 raw materials (limestone)
\$0.26 operating labor;

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\$2.64 maintenance;
\$0.07 miscellaneous.

Total O&M cost per ton of coal burned = \$3.43

2.4 Flue Gas Reheat Cost: \$0.05

2.5 Total FGD Cost Per Ton of Coal: \$15.90

2.6 FGD Cost per MMStu: \$0.68

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CASE NUMBERS: 6A, 6B, 6C, and 6D

Coal Source Area: Armstrong County, Pennsylvania

Coal Use Area: Springfield, Massachusetts

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CASE NUMBER: 6A

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Springfield, Massachusetts
- 1.2 Emission Standard: New Plant, 0.55 lb S per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Pennsylvania
County: Armstrong Coalbed: Upper Freeport
- 1.5 Raw Coal: 2.40% S, 12.3% Ash, 25.100 MMBtu/ton,
3.82 SO₂/MMBtu
- 1.6 Cleaned Coal: 87% cleaning plant wt. yield,
94% cleaning plant Btu recovery, 27.12 MMBtu/ton,
0.97% S, 5.8% Ash, 1.43 lb. SO₂/MMBtu, 8.0% Btu
increase per unit wt. on cleaning.
- 1.7 Coal Transportation: 659 miles, \$15.32/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 25 yrs. remaining
life, 7000 hrs./year, 1.2906 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity,
utilized 260 days/ yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 128 MW_e minimum requirement, 147 MW_e
design size, \$MM 21.04 capital cost, 17.85% annual cap.
chrg., \$MM 3.756 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 30% of flue gas scrubbed, 0% of full
scale reheat required, MMBtu/yr. full reheat,
\$ /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.07 for amortization,
\$3.44 for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$2.24/ton
\$20.00/ton, additional coal cost is \$2.99/ton
\$25.00/ton, additional coal cost is \$3.74/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.20/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$6.95
\$20.00/ton, total additional cost is: \$7.70
\$25.00/ton, total additional cost is: \$8.45
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$2.91
- 2.2.2 Fuel & Electricity Cost: \$0.37
- 2.2.3 O&M Costs: \$0.09 raw materials (limestone), \$0.15 operating labor; \$0.75 maintenance; \$0.03 miscellaneous.
Total O&M cost per ton of coal burned = \$1.02.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$4.30
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$2.22/ton
\$40.00/ton, added coal value is \$2.96/ton
\$50.00/ton, added coal value is \$3.70/ton
- 2.3.2 Transportation Cost Saving: \$1.13/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.50/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.06/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.10/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$1.29/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price is:

\$30.00/ton, the total benefit is \$5.30/ton

\$40.00/ton, the total benefit is \$6.04/ton

\$50.00/ton, the total benefit is \$6.78/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	5.95	5.21	4.47
	\$20	6.70	5.96	5.22
	\$25	7.45	6.71	5.97

2.4.2 Cost Per Million Btu Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.22	0.19	0.16
	\$20	0.25	0.22	0.19
	\$25	0.27	0.25	0.22

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CASE NUMBER: 6B

1.0 CASE CONDITIONS

1.1 Coal Use Area: Springfield, Massachusetts

1.2 Emission Standard: New Plant, 0.55 lb S per MMBtu

1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)

1.4 Origin of Coal: State: Pennsylvania

County: Armstrong Coalbed: Upper Freeport

1.5 Raw Coal:

2.40% S 12.3% Ash 25.10 MMBtu/ton

3.82 lb SO₂/MMBtu

1.6 Assumed Electric Utility Plant: 500 MW_e,

25 yrs. remaining life,

7000 hrs./year,

1.3944 MMtons/yr.

1.7 Flue Gas Scrubber:

396 MW_e minimum requirement,

455 MW_e design size, \$MM 60.93 capital cost,

17.85 % annual cap. chrg., \$MM 10.876 cap. chrg./yr.

1.8 Flue Gas Reheat:

91 % of flue gas scrubbed,

70 % of full scale reheat required,

490,000 MMBtu/yr. full reheat, \$980,000/yr. for

full reheat.

2.0 FGD COSTS PER TON OF CLEANED COAL BURNED

2.1 Capital Contribution: \$7.80

2.2 Fuel & Electricity Cost: 1.11

2.3 O&M Costs:

\$0.66 raw materials (limestone)

\$0.20 operating labor;

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\$2.01 maintenance;

\$0.09 miscellaneous.

Total O&M cost per ton of coal burned = \$2.96

2.4 Flue Gas Reheat Cost: \$0.49

2.5 Total FGD Cost Per Ton of Coal: \$12.36

2.6 FGD Cost per MMBtu: \$0.49

CASE NUMBER: 6C

1.0 CASE CONDITIONS

- 1.1 Coal Use Area: Springfield, Massachusetts
- 1.2 Emission Standard: Existing Plant, 0.55 lb S per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Pennsylvania
County: Armstrong Coalbed: Upper Freeport
- 1.5 Raw Coal: 2.40% S, 12.3% Ash, 25.10 MMBtu/ton,
3.82 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 87% cleaning plant wt. yield,
94% cleaning plant Btu recovery, 27.12 MMBtu/ton,
0.97% S, 5.8% Ash, 1.43 lb. SO₂/MMBtu,
8.0 % Btu increase per unit wt. on cleaning.
- 1.7 Coal Transportation: 659 miles, \$15.32/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 15 yrs.
remaining life, 5000 hrs./year, 0.9218 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity,
utilized 260 days/yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 128 MW_e minimum requirement, 147 MW_e
design size, \$MM 26.30 capital cost, 20.12 % annual cap. chrg.,
\$MM 5.292 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 30% of flue gas scrubbed, 0 % of full
scale reheat required, - MMBtu/yr. full reheat, \$ - /
yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.07 for amortization, \$3.44
for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$2.24/ton
\$20.00/ton, additional coal cost is \$2.99/ton
\$25.00/ton, additional coal cost is \$3.74/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.20/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$6.95
\$20.00/ton, total additional cost is: \$7.70
\$25.00/ton, total additional cost is: \$8.45
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$5.74
- 2.2.2 Fuel & Electricity Cost: \$0.37
- 2.2.3 O&M Costs: \$0.09 raw materials (limestone), \$0.20 operating labor; \$1.31 maintenance; \$0.03 miscellaneous.
Total O&M cost per ton of coal burned = \$1.63.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$7.74
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$2.22/ton
\$40.00/ton, added coal value is \$2.96/ton
\$50.00/ton, added coal value is \$3.70/ton
- 2.3.2 Transportation Cost Saving: \$1.13/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.50/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.06/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.10/ton

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2.3.6 Saving in Utility Maintenance Cost: \$1.29/ton

2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B. Mine Price is:

\$30.00/ton, the total benefit is \$5.30/ton

\$40.00/ton, the total benefit is \$6.04/ton

\$50.00/ton, the total benefit is \$6.78/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	9.39	8.65	7.91
	\$20	10.14	9.40	8.66
	\$25	10.89	10.15	9.41

2.4.2 Cost Per Million Btu Burned to Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.35	0.32	0.29
	\$20	0.37	0.35	0.32
	\$25	0.40	0.37	0.35

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CASE NUMBER: 6D

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Springfield, Massachusetts
- 1.2 Emission Standard: Existing Plant, 0.55 lb S per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Pennsylvania
County: Armstrong Coalbed: Upper Freeport
- 1.5 Raw Coal:
2.40XS 12.3% Ash 25.10 MMBtu/ton
3.82 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
15 yrs. remaining life,
5000 hrs./year,
0.9960 MMtons/yr.
- 1.7 Flue Gas Scrubber:
396 MW_e minimum requirement,
455 MW_e design size, \$MM 76.16 capital cost,
20.12 % annual cap. chrg., \$MM 15.323 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
91% of flue gas scrubbed,
70% of full scale reheat required,
350,000 MMBtu/yr. full reheat \$700,000/yr. for
full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$15.38
- 2.2 Fuel & Electricity Cost: \$1.11
- 2.3 O&M Costs:
\$0.66 raw materials (limestone),
\$0.28 operating labor;

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\$3.52 maintenance;

\$0.09 miscellaneous.

Total O&M cost per ton of coal burned = \$4.55.

2.4 Flue Gas Reheat Cost: \$0.49

2.5 Total FGD Cost Per Ton of Coal: \$21.53

2.6 FGD Cost per MMBtu: \$0.86

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CASE NUMBERS: 7A, 7B, 7C, and 7D

Coal Source Area: Jefferson County, Ohio

Coal Use Area: Lansing, Michigan

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CASE NUMBER: 7A

1.0 CASE CONDITIONS

- 1.1 Coal Use Area: Lansing, Michigan
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Ohio
County: Jefferson Coalbed: Pittsburgh
- 1.5 Raw Coal: 2.66% S, 9.3% Ash, 25.22 MMBtu/ton,
4.22 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 85% cleaning plant wt. yield, 90% cleaning
plant Btu recovery, 26.71 MMBtu/ton, 1.80% S, 5.1% Ash,
2.70 lb. SO₂/MMBtu, 5.9 % Btu increase per unit wt. on
cleaning.
- 1.7 Coal Transportation: 323 miles, \$6.58/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 25 yrs. remaining
life, 7000 hrs./year, 1.3104 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity,
utilized 260 days/yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 309 MW_e minimum requirement, 355 MW_e
design size, \$MM 46.78 capital cost, 17.85% annual cap.
charge, \$MM 8.350 capital charge per year.
- 1.12 Flue Gas Reheat: 71% of flue gas scrubbed, 0% of full
scale reheat required, - MMBtu/yr. full reheat,
\$ - /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.10 for amortization,
\$3.51 for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$2.65/ton
\$20.00/ton, additional coal cost is \$3.53/ton
\$25.00/ton, additional coal cost is \$4.41/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.21/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$7.47
\$20.00/ton, total additional cost is: \$8.35
\$25.00/ton, total additional cost is: \$9.23
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$6.37
- 2.2.2 Fuel & Electricity Cost: \$0.87
- 2.2.3 O&M Costs: \$0.38 raw materials (limestone),
\$0.21 operating labor; \$1.64 maintenance; \$0.07
miscellaneous. Total O&M cost per ton of coal
burned = \$2.30.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$9.54
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$1.67/ton
\$40.00/ton, added coal value is \$2.23/ton
\$50.00/ton, added coal value is \$2.79/ton
- 2.3.2 Transportation Cost Saving: \$0.37/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.31/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.04/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.08/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$0.84/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price is:

\$30.00/ton, the total benefit is \$3.31/ton

\$40.00/ton, the total benefit is \$3.87/ton

\$50.00/ton, the total benefit is \$4.43/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	13.70	13.14	12.58
	\$20	14.58	14.02	13.46
	\$25	15.56	14.90	14.34

2.4.2 Cost Per Million Btu Burned to Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.51	0.49	0.47
	\$20	0.55	0.53	0.50
	\$25	0.58	0.56	0.54

CASE NUMBER: 7B

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Lansing, Michigan
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Ohio
County: Jefferson Coalbed: Pittsburgh
- 1.5 Raw Coal:
2.66% S 9.3% Ash 25.22 MMBtu/ton
4.22 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
25 yrs. remaining life,
7000 hrs./year,
1.3876 MMtons/yr.
- 1.7 Flue Gas Scrubber:
398 MW_e minimum requirements,
457 MW_e design size, \$MM 62.89 capital cost,
17.85 % annual cap. chrg., \$MM 11.226 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
92 % of flue gas scrubbed
74% of full scale reheat required,
490,000 MMBtu/yr. full reheat, \$980,000/yr. for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$8.09
- 2.2 Fuel & Electricity Cost: \$1.12
- 2.3 O&M Costs:
\$0.73 raw materials (limestone),
\$0.20 operating labor;

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\$2.08 maintenance;

\$0.09 miscellaneous.

Total O&M cost per ton of coal burned = \$3.10.

2.4 Flue Gas Reheat Cost: \$0.52

2.5 Total FGD Cost Per Ton of Coal: \$12.83

2.6 FGD Cost per MMBtu: \$0.51

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CASE NUMBER: 7C

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Lansing, Michigan
- 1.2 Emission Standard: Existing Plant, 1.6 lb SO₂ MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Ohio
County: Jefferson Coalbed: Pittsburgh
- 1.5 Raw Coal: 2.66 XS, 9.3% Ash, 25.22 MMBtu/ton,
4.22 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 85% cleaning plant wt. yield,
90% cleaning plant Btu recovery, 26.71 MMBtu/ton, 1.80XS,
5.1% Ash, 2.70 lb. SO₂/MMBtu, 5.9 % Btu increase per unit
wt. on cleaning.
- 1.7 Coal Transportation: 323 miles, \$6.58/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 15 yrs. remaining
life, 5000 hrs./year, 0.9360 MMtons/ coal yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity,
utilized 260 days/ yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 227 MW_e minimum requirement, 260 MW_e design
size, \$MM 45.72 capital cost, 20.12 % annual cap. chrg.,
\$MM 9.20 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 52% of flue gas scrubbed, 0% of full scale
reheat required, - MMBtu/yr. full reheat, \$ - /yr.
for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.10 for amortization,
\$3.51 for O&M

- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
 \$15.00/ton, additional coal cost is \$2.65/ton
 \$20.00/ton, additional coal cost is \$3.353/ton
 \$25.00/ton, additional coal cost is \$4.41/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.21/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
 \$15.00/ton, total additional cost is: \$7.47
 \$20.00/ton, total additional cost is: \$8.35
 \$25.00/ton, total additional cost is: \$9.23
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$9.83
- 2.2.2 Fuel & Electricity Cost: \$0.63
- 2.2.3 O&M Costs: \$0.28 raw materials (limestone), \$0.30 operating labor; \$2.25 maintenance; \$0.05 miscellaneous. Total O&M cost per ton of coal burned = \$2.88.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$13.34.
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
 \$30.00/ton, added coal value is \$1.67/ton
 \$40.00/ton, added coal value is \$2.23/ton
 \$50.00/ton, added coal value is \$2.79/ton
- 2.3.2 Transportation Cost Saving: \$0.37/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.31/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.04/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.08/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$0.84/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price is:

\$30.00/ton, the total benefit is \$3.31/ton

\$40.00/ton, the total benefit is \$3.87/ton

\$50.00/ton, the total benefit is \$4.43/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (per Ton)	\$15	17.50	16.94	16.38
	\$20	18.38	17.82	17.26
	\$25	19.26	18.70	18.14

2.4.2 Cost Per Million Btu Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.66	0.64	0.61
	\$20	0.69	0.67	0.65
	\$25	0.72	0.70	0.68

CASE NUMBER: 7D

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Lansing, Michigan
- 1.2 Emission Standard: Existing Plant, 1.6 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Ohio
County: Jefferson Coalbed: Pittsburgh
- 1.5 Raw Coal:
2.66% S 9.3% Ash 25.22 MMBtu/ton
4.22 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
15 yrs. remaining life,
5000 hrs./year,
0.9911 MMtons/yr.
- 1.7 Flue Gas Scrubber:
345 MW_e minimum requirement,
397 MW_e design size, \$MM 70.34 capital cost,
20.12 % annual cap. chrg., \$MM 14.152 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
80% of flue gas scrubbed,
34% of full scale reheat required,
350,000 MMBtu/yr. full reheat, \$700,000/yr. for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$14.28
- 2.2 Fuel & Electricity Cost: \$0.98
- 2.3 O&M Costs:
\$0.64 raw materials (limestone),
\$0.28 operating labor;

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\$3.26 maintenance;

\$0.08 miscellaneous.

Total O&M cost per ton of coal burned = \$4.26

2.4 Flue Gas Reheat Cost: \$0.24

2.5 Total FGD Cost Per Ton of Coal: \$19.76

2.6 FGD Cost per MMBtu: \$0.78



CASE NUMBERS: 8A, 8B, 8C, and 8 D
Coal Source Area: Vigo County, Indiana
Coal Use Area: Nashville (Gallatin), Tennessee

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CASE NUMBER: 8A

1.0 CASE CONDITIONS

- 1.1 Coal Use Area: Nashville (Gallatin), Tennessee
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Indiana
County: Vigo Coalbed: No. VII
- 1.5 Raw Coal: 1.34% S, 10.8% Ash, 23.09 MMBtu/ton,
2.32 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 92% cleaning plant wt. yield, 96% cleaning
plant Btu recovery, 24.09 MMBtu/ton, 0.84% S, 7.6% Ash,
1.39 lb SO₂/MMBtu, 4.35 % Btu increase per unit wt. on
cleaning.
- 1.7 Coal Transportation: 288 miles, \$6.85/ton
- 1.8 Assumed Electric Utility Plant: 500 MW₃, 25 yrs. remaining
life, 7000 hrs./year, 1.4528 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$17.50/ton hr. input capacity, utilized
260 days/ yr. @ 13 hrs./day (38.58% utilization), level
payment amortization
- 1.11 Flue Gas Scrubber: 76 MW_e minimum requirement, 87 MW_e design
size, \$MM 13.66 capital cost. 17.85% annual cap. chrg.,
\$MM 2.438 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 18 % of flue gas scrubbed, 0% of full
scale reheat required, - MMBtu/yr. full reheat,
\$ - /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$0.87 for amortization, \$3.25
for O&M

- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$1.30/ton
\$20.00/ton, additional coal cost is \$1.74/ton
\$25.00/ton, additional coal cost is \$2.17/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.17/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$5.59
\$20.00/ton, total additional cost is: \$6.03
\$25.00/ton, total additional cost is: \$6.46
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$1.68
- 2.2.2 Fuel & Electricity Cost: \$0.22
- 2.2.3 O&M Costs: \$0.05 raw materials (limestone), \$0.13 operating labor; \$0.43 maintenance; \$0.02 miscellaneous.
Total O&M cost per ton of coal burned = \$0.63
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$2.53
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$1.25/ton
\$40.00/ton, added coal value is \$1.67/ton
\$50.00/ton, added coal value is \$2.08/ton
- 2.3.2 Transportation Cost Saving: \$0.29/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.23/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.03/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.06/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$0.53/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B. Mine
Price is:

\$30.00/ton, the total benefit is \$2.39/ton

\$40.00/ton, the total benefit is \$2.81/ton

\$50.00/ton, the total benefit is \$3.22/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (of value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	5.73	5.31	4.90
	\$20	6.17	5.75	5.34
	\$25	6.60	6.18	5.77

2.4.2 Cost Per Million Btu Burned To Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.24	0.22	0.20
	\$20	0.26	0.24	0.22
	\$25	0.27	0.26	0.24

CASE NUMBER: 8B

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Nashville (Gallatin), Tennessee
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Indiana
County: Vigo Coalbed: No. VII
- 1.5 Raw Coal:
1.34XS 10.8% Ash 23.09 MMBtu/ton
2.32 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
25 yrs. remaining life
7000 hrs./year,
1.5159 MMtons/yr.
- 1.7 Flue Gas Scrubber:
268 MW_e minimum requirement,
308 MW_e design size, \$MM 39.55 capital cost,
17.85 % annual cap. chrg., \$MM 7.060 cap. chrg/yr.
- 1.8 Flue Gas Reheat:
62 % of flue gas scrubbed,
0 % of full scale reheat required,
MMBtu/yr. full reheat, \$ - /yr. for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$4.66
- 2.2 Fuel & Electricity Cost: \$0.76
- 2.3 O&M Costs:
\$0.25 raw materials (limestone),
\$0.19 operating labor;

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\$1.20 maintenance;

\$0.06 miscellaneous.

Total O&M cost per ton of coal burned = \$1.70

2.4 Flue Gas Reheat Cost: \$ -0-

2.5 Total FGD Cost Per Ton of Coal: \$7.12

2.6 FGD Cost per MMBtu: \$0.31

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CASE NUMBER: 8C

1.0 CASE CONDITIONS

1.1 Coal Use Area: Nashville (Gallatin), Tennessee

1.2 Emission Standard: Existing Plant, 1.2 lb SO₂ per MMBtu

1.3 SO₂ Control Method: Combined use of coal cleaning & FGD

1.4 Origin of Coal: State: Indiana

County: Vigo

Coalbed: No. VII

1.5 Raw Coal: 1.34% S, 10.8% Ash, 23.09 MMBtu/ton,
2.32 lb. SO₂/MMBtu

1.6 Cleaned Coal: 92% cleaning plant wt. yield, 96% cleaning
plant Btu recovery, 24.09 MMBtu/ton, 0.84% S,
7.6% Ash, 1.39 lb. SO₂/MMBtu, 4.35% Btu increase per
unit wt. on cleaning.

1.7 Coal Transportation: miles, \$ /ton

1.8 Assumed Electric Utility Plant: 50 MW_e, 15 yrs. remaining
life, 5000 hrs./year, 1.0377 MMtons coal/yr.

1.9 Utility Ash Disposal Cost: \$7.00/ton

1.10 Coal Cleaning Plant: \$17,150/ton/hr. input capacity,
utilized 260 days/yr. @ 13 hrs./day (38.58% utilization), level
payment amortization

1.11 Flue Gas Scrubber: 76 MW_e minimum requirement, 87 MW_e design
size, \$MM 17.08 capital cost, 20.12% annual cap. chrg.,
\$MM 3.436 cap. chrg./yr.

1.12 Flue Gas Reheat: 18% of flue gas scrubbed, 0% of full
scale reheat required, - MMBtu/yr. full reheat,
\$ - /yr. for full reheat.

2.0 ECONOMIC ASSESSMENT

2.1 Coal Cleaning Cost Per Ton of Cleaned Coal

2.1.1 Cleaning Plant Costs: \$0.87 for amortization, \$3.25 for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$1.30/ton
\$20.00/ton, additional coal cost is \$1.74/ton
\$25.00/ton, additional coal cost is \$2.17/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.17/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$5.59
\$20.00/ton, total additional cost is: \$6.03
\$25.00/ton, total additional cost is: \$6.46
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$3.31
- 2.2.2 Fuel & Electricity Cost: \$0.22
- 2.2.3 O&M Costs: \$.0.05 raw materials (limestone),
\$0.18 operating labor; \$0.76 maintenance; \$0.02 miscellaneous.
Total O&M cost per ton of coal burned = \$1.01.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$4.54.
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$1.25/ton
\$40.00/ton, added coal value is \$1.67/ton
\$50.00/ton, added coal value is \$2.08/ton
- 2.3.2 Transportation Cost Saving: \$0.29/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.23/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.03/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.06/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$0.53/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price is:

\$30.00/ton, the total benefit is \$2.39/ton

\$40.00/ton, the total benefit is \$2.81/ton

\$50.00/ton, the total benefit is \$3.22/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	7.74	7.32	6.91
	\$20	8.18	7.76	7.35
	\$25	8.61	8.19	7.78

2.4.2 Cost Per Million Btu Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.32	0.30	0.29
	\$20	0.34	0.32	0.31
	\$25	0.36	0.34	0.32

CASE NUMBER: 8D

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Nashville (Gallatin), Tennessee
- 1.2 Emission Standard: Existing Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Indiana
County: Vigo Coalbed: No. VII
- 1.5 Raw Coal:
1.34% S 10.8% Ash 23.09 MMBtu/ton
2.32 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
15 yrs. remaining life,
5000 hrs./year,
1.0828 MMtons/yr.
- 1.7 Flue Gas Scrubber:
268 MW_e minimum requirement,
308 MW_e design size, \$MM 49.44 capital cost,
20.12% annual cap. chrg., \$MM 9.947 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
62% of Flue gas scrubbed,
0% of full scale reheat required,
MMBtu/yr. full reheat, \$ - /yr. for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$9.19
- 2.2 Fuel & Electricity Cost: \$0.76
- 2.3 O&M Costs:
\$0.25 raw materials (limestone),
\$0.26 operating labor;

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\$2.10 maintenance;

\$0.06 miscellaneous.

Total O&M cost per ton of coal burned = \$2.67.

2.4 Flue Gas Reheat Cost: \$ -0-

2.5 Total FGD Cost Per Ton of Coal: \$12.62

2.6 FGD Cost per MMBtu: \$0.55

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CASE NUMBERS: 9A, 9B, 9C, and 9D

Coal Source Area: Garrett County, Maryland

Coal Use Area: Burlington, New Jersey

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CASE NUMBER: 9A

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Burlington, New Jersey
- 1.2 Emission Standard: New Plant, 0.30 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Maryland
County: Garrett Coalbed: Upper Freeport
- 1.5 Raw Coal: 2.25% S, 13.1% Ash, 25.29 MMBtu/ton,
3.56 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 79% cleaning plant wt. yield, 86%
cleaning plant Btu recovery, 27.53 MMBtu/ton, 1.24% S,
6.7% Ash, 1.80 lb. SO₂/MMBtu, 8.9% Btu increase per unit
wt. on cleaning.
- 1.7 Coal Transportation: 302 miles, \$11.32/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 25 yrs.
remaining life, 7000 hrs./year, 1.2714 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity,
utilized 260 days/ yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 463 MW_e minimum requirement,
532 MW_e design size, \$MM capital cost, 17.85% annual
cap. chrg., \$MM cap. chrg./yr.
- 1.12 Flue Gas Reheat: % of flue gas scrubbed, % of
full scale reheat required, MMBtu/yr. full reheat,
/yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$ for amortization, \$
for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
 \$15.00/ton, additional coal cost is \$ /ton
 \$20.00/ton, additional coal cost is \$ /ton
 \$25.00/ton, additional coal cost is \$ /ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$ /ton
- 2.1.4 Total Differential Cost of Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
 \$15.00/ton, total additional cost is: \$
 \$20.00/ton, total additional cost is: \$
 \$25.00/ton, total additional cost is: \$
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$
- 2.2.2 Fuel & Electricity Cost:
- 2.2.3 O&M Costs: \$ raw materials (limestone), \$
 operating labor; \$ maintenance; \$
 miscellaneous. Total O&M cost per ton of coal
 burned = \$
- 2.2.4 Flue Gas Reheat Cost: \$
- 2.2.5 Total FGD Cost Per Ton of Coal: \$
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
 \$30.00/ton, added coal value is \$ /ton
 \$40.00/ton, added coal value is \$ /ton
 \$50.00/ton, added coal value is \$ /ton
- 2.3.2 Transportation Cost Saving: \$ /ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$ /ton
- 2.3.5 Saving in Pension Fund Payment: \$ /ton
- 2.3.6 Saving in Utility Maintenance Cost: \$ /ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price Is:

\$30.00/ton, the total benefit is \$ /ton

\$40.00/ton, the total benefit is \$ /ton

\$50.00/ton, the total benefit is \$ /ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

	<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15		
of Raw Coal (Per Ton)	\$20		
	\$25		

2.4.2 Cost Per Million Btu Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

	<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15		
of Raw Coal (Per Ton)	\$20		
	\$25		

(TOO LITTLE MARGIN WITH FGD FOR STUDY CONSIDERATION)

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CASE NUMBER: 9B

1.0 CASE CONDITIONS

1.1 Coal Use Area: Burlington, New Jersey

1.2 Emission Standard: New Plant, 0.30 lb SO₂ per MMBtu

1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)

1.4 Origin of Coal: State: Maryland

County: Garrett Coalbed: Upper Freeport

1.5 Raw Coal:

2.25% S 13.1% Ash 25.29 MMBtu/ton

3.56 lb SO₂/MMBtu

1.6 Assumed Electric Utility Plant: 500 MW_e,

25 yrs. remaining life,

7000 hrs./year,

1.3841 MMtons/yr. 1.7

1.7 Flue Gas Scrubber:

MW_e minimum requirement,

MW_e design size, \$MM capital cost,

% annual cap. chrg., \$MM cap. chrg./yr.

1.8 Flue Gas Reheat:

% of flue gas scrubbed,

% of full scale reheat required,

MMBtu/yr full reheat, \$ /yr. for full reheat.

2.0 FGD COSTS PER TON OF CLEANED COAL BURNED

2.1 Capital Contribution: \$

2.2 Fuel & Electricity Cost:

2.3 O&M Costs: \$

\$ raw materials (limestone),

\$ operating labor;

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\$ maintenance;

\$ miscellaneous.

Total O&M cost per ton of coal burned = \$

2.4 Flue Gas Reheat Cost: \$

2.5 Total FGD Cost Per Ton of Coal: \$

(CANNOT USE FGD TO MEET SO₂ STANDARD)

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CASE NUMBER: 9C

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Burlington, New Jersey
- 1.2 Emission Standard: Existing Plant, 1 percent S by weight
(or equivalent emission)
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Maryland
County: Garrett Coalbed: Upper Freeport
- 1.5 Raw Coal: 2.25% S, 13.1% Ash, 25.29 MMBtu/ton,
3.56 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 79% cleaning plant wt. yield, 86% cleaning
plant Btu recovery, 27.53 MMBtu/ton, 1.24% S, 6.7% Ash,
1.80 lb. SO₂/MMBtu, 8.9% Btu increase per unit wt. on
cleaning.
- 1.7 Coal Transportation: 302 miles, \$11.32/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 15 yrs.
remaining life, 5000 hrs./year, 0.9082 MMtons/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity,
utilized 260 days/ yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 108 MW_e minimum requirement, 124 MW_e
design size, \$MM 23.80 capital cost, 20.12% annual
cap. chrg. \$MM 4.789 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 25% of flue gas scrubbed, 0% of full
scale reheat required, - MMBtu/yr. full reheat,
\$ - /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.18 for amortization, \$3.78 for
O&M

- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$3.99/ton
\$20.00/ton, additional coal cost is \$5.32/ton
\$25.00/ton, additional coal cost is \$6.65/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.22/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide
One Ton of Cleaned Coal. When the Mine Operator's
Cost is:
\$15.00/ton, total additional cost is: \$ 9.17
\$20.00/ton, total additional cost is: \$10.50
\$25.00/ton, total additional cost is: \$11.83
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$5.27
- 2.2.2 Fuel & Electricity Cost: \$0.31
- 2.2.3 O&M Costs: \$0.09 raw materials (limestone), \$0.21
operating labor; \$1.21 maintenance; \$0.03 miscellaneous.
Total O&M cost per ton of coal burned = \$1.54.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$7.12
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher
Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$2.45/ton
\$40.00/ton, added coal value is \$3.27/ton
\$50.00/ton, added coal value is \$4.09/ton
- 2.3.2 Transportation Cost Saving: \$0.93/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.48/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.07/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.11/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$1.07/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B. Mine Price is:

\$30.00/ton, the total benefit is \$5.11/ton

\$40.00/ton, the total benefit is \$5.93/ton

\$50.00/ton, the total benefit is \$6.75/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	\$11.18	\$10.36	\$ 9.54
of Raw Coal (Per Ton)	\$20	12.51	11.69	10.87
	\$25	13.84	13.02	12.20

2.4.2 Cost Per Million Btu Burned To Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	0.41	0.38	0.35
of Raw Coal (Per Ton)	\$20	0.45	0.42	0.39
	\$25	0.50	0.47	0.44

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CASE NUMBER: 9D

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Burlington, New Jersey
- 1.2 Emission Standard: Existing Plant, 1 percent S by weight (or equivalent emission)
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Maryland
County: Garrett Coalbed: Upper Freeport
- 1.5 Raw Coal: 2.25% S, 13.1% Ash, 25.29 MMBtu/ton,
3.56 lb. SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
15 yrs. remaining life,
5000 hrs./year,
0.9886 MMtons/yr.
- 1.7 Flue Gas Scrubber:
309 MW_e minimum requirement,
355 MW_e design size, \$MM 61.57 capital cost,
20.12% annual cap. chrg., \$MM 12.388 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
71% of flue gas scrubbed,
4% of full scale reheat required,
350,000 MMBtu/yr. full reheat, \$700,000/yr.
for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$12.53
- 2.2 Fuel & Electricity Cost: \$0.87
- 2.3 O&M Costs:
\$0.48 raw materials (limestone),
\$0.28 operating labor;

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\$2.86 maintenance;

\$0.07 miscellaneous.

Total O&M cost per ton of coal burned = \$3.69.

2.4 Flue Gas Reheat Cost: \$0.03

2.5 Total FGD Cost Per Ton of Coal: \$17.12

2.6 FGD Cost per MMBtu: \$0.68

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CASE NUMBERS: 10A, 10B, 10C, and 10D
Coal Source Area: Franklin County, Illinois
Coal Use Area: Milwaukee, Wisconsin

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CASE NUMBER: 10A

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Milwaukee, Wisconsin
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Illinois
County: Franklin Coalbed: No. 6
- 1.5 Raw Coal: 1.09% S, 13.7% Ash, 23.00 MMBtu/ton,
1.90 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 88% cleaning plant wt. yield,
96% cleaning plant Btu recovery, 25.09 MMBtu/ton,
0.94% S, 6.14% Ash, 1.50 lb. SO₂/MMBtu,
9.1% Btu increase per unit wt. on cleaning.
- 1.7 Coal Transportation: 375 miles, \$5.83/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 25 yrs.
remaining life, 7000 hrs./year, 1.3951 MMtons
coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$17,150/ton/hr. input capacity,
utilized 260 days/yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 111 MW_e minimum requirement, 128 MW_e
design size, \$MM 18.78 capital cost, 17.85% annual cap. chrg.,
\$MM 3.352 cap. chrg.
- 1.12 Flue Gas Reheat: 26% of flue gas scrubbed, 0% of full
scale reheat required, - MMBtu/yr. full reheat,
\$ - /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$0.91 for amortization,
\$3.40 for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$2.04/ton
\$20.00/ton, additional coal cost is \$2.73/ton
\$25.00/ton, additional coal cost is \$3.41/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.17/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide
One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$6.53
\$20.00/ton, total additional cost is: \$7.21
\$25.00/ton, total additional cost is: \$7.89
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$2.40
- 2.2.2 Fuel & Electricity Cost: \$0.32
- 2.2.3 O&M Costs: \$0.07 raw materials (limestone), \$0.13
operating labor; \$0.62 maintenance; \$0.03 miscellaneous.
Total O&M cost per ton of coal burned = \$0.85.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$3.57
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal When Value Per Ton of Cleaned Coal Due to
Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$2.50/ton
\$40.00/ton, added coal value is \$3.34/ton
\$50.00/ton, added coal value is \$4.17/ton
- 2.3.2 Transportation Cost Saving: \$0.49/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.56/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.07/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.12/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$0.73/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the
F.O.B. Mine Price is:

\$30.00/ton, the total benefit is \$4.47/ton

\$40.00/ton, the total benefit is \$5.31/ton

\$50.00/ton, the total benefit is \$6.14/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	5.63	4.79	3.96
	\$20	6.31	5.47	4.64
	\$25	6.99	6.15	5.32

2.4.2 Cost Per Million Btu Burned To Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.22	0.19	0.16
	\$20	0.25	0.22	0.18
	\$25	0.28	0.25	0.21

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CASE NUMBER: 10B

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Milwaukee, Wisconsin
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Illinois
County: Franklin Coalbed: No. 6
- 1.5 Raw Coal:
1.09% S 1.37% Ash 23.00 MMBtu/ton
1.90 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
25 yrs. remaining life,
7000 hrs./yr.,
1.5217 MMtons/yr.
- 1.7 Flue Gas Scrubber:
205 MW_e minimum requirement,
235 MW_e design size, \$MM 30.95 capital cost,
17.85% annual cap. chrg., \$MM 5.525 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
47% of flue gas scrubbed,
0% of full scale reheat required,
MMBtu/yr. full reheat, \$ /yr. for
full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$3.63
- 2.2 Fuel & Electricity Cost: \$0.57
- 2.3 O&M Costs:
\$0.15 raw materials (limestone),
\$0.18 operating labor;

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\$0.94 maintenance;

\$0.05 miscellaneous.

Total O&M cost per ton of coal burned = \$1.32.

2.4 Flue Gas Reheat Cost: \$ -0-

2.5 Total FGD Cost Per Ton of Coal: \$5.52

2.6 FGD Cost per MMBtu: \$0.24

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CASE NUMBER: 10C

1.0 CASE CONDITIONS

- 1.1 Coal Use Area: Milwaukee, Wisconsin
- 1.2 Emission Standard: Existing Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Illinois
County: Franklin Coalbed: No. 6
- 1.5 Raw Coal: 1.09% S, 13.7% Ash, 23.00 MMBtu/ton,
1.90 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 88% cleaning plant wt. yield, 96% cleaning
plant Btu recovery, 25,088 MMBtu/ton, 0.94% S, 6.4% Ash,
1.50 lb. SO₂/MMBtu, 9.1% Btu increase per unit wt. on
cleaning.
- 1.7 Coal Transportation: 375 miles, \$5.83/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 15 yrs.
remaining life, 5000 hrs./year, 0.9965 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$17,150/ton/hr. input capacity,
utilized 260 days/yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 111 MW_e minimum requirement, 128 MW_e
design size, \$MM 23.48 capital cost, 20.12% annual cap. chrg.,
\$MM 4,724 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 26% of flue gas scrubbed, 0% of full
scale reheat required, - MMBtu/yr. full reheat,
\$ - /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$0.91 for amortization,
\$3.40 for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$2.04/ton
\$20.00/ton, additional coal cost is \$2.73/ton
\$25.00/ton, additional coal cost is \$3.41/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.17/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$6.53
\$20.00/ton, total additional cost is: \$7.21
\$25.00/ton, total additional cost is: \$7.89
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$4.74
- 2.2.2 Fuel & Electricity Cost: \$0.32
- 2.2.3 O&M Costs: \$0.07 raw materials (limestone), \$0.19 operating labor; \$1.08 maintenance; \$0.03 miscellaneous.
Total O&M cost per ton of coal burned = \$1.37.
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$6.43
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$2.50/ton
\$40.00/ton, added coal value is \$3.34/ton
\$50.00/ton, added coal value is \$4.17/ton
- 2.3.2 Transportation Cost Saving: \$0.49/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.56/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.07/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.12/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$0.73/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B. Mine Price is:

\$30.00/ton, the total benefit is \$4.47/ton

\$40.00/ton, the total benefit is \$5.31/ton

\$50.00/ton, the total benefit is \$6.14/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal. price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	8.49	7.65	6.82
	\$20	9.17	8.33	7.50
	\$25	9.85	9.01	8.18

2.4.2 Cost Per Million Btu Burned To Meet Emission Standard

		<u>F.O.B. Mine Raw Coal Price (Per Ton)</u>		
		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.34	0.30	0.27
	\$20	0.37	0.33	0.30
	\$25	0.39	0.36	0.33

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CASE NUMBER: 10D

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Milwaukee, Wisconsin
- 1.2 Emission Standard: Existing Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Illinois
County: Franklin Coalbed: No. 6
- 1.5 Raw Coal:
1.09% S, 13.7% Ash, 23.00 MMBtu/ton, 1.90 lb.
SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
15 yrs. remaining life,
5000 hrs./yr.,
1.0870 MMtons/yr.
- 1.7 Flue Gas Scrubber:
205 MW_e minimum requirement,
235 MW_e design size, \$MM 38.69 capital cost,
20.12% annual cap. chrg., \$MM 7.784 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
47% of flue gas scrubbed,
0% of full scale reheat required,
MMBtu/yr. full reheat, \$ /yr. for full
reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$7.16
- 2.2 Fuel & Electricity Cost: \$0.57
- 2.3 O&M Costs: \$
\$0.15 raw materials (limestone),
\$0.26 operating labor;

\$1.64 maintenance;

\$0.05 miscellaneous.

Total O&M cost per ton of coal burned = \$2.10.

2.4 Flue Gas Reheat Cost: \$-0-

2.5 Total FGD Cost Per Ton of Coal: \$9.83

2.6 FGD Cost per MMBtu: \$0.43

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CASE NUMBERS: 11A, 11B, 11C, and 11D
Coal Source Area: Greene County, Pennsylvania
Coal Use Area: Concord, New Hampshire

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CASE NUMBER: 11A

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Concord, New Hampshire
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Pennsylvania
County: Greene Coalbed: Sewickley
- 1.5 Raw Coal: 3.26% S, 10.8% Ash, 25.23 MMBtu/ton,
5.17 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 84.6% cleaning plant wt. yield, 88.5%
cleaning plant Btu recovery, 26.39 MMBtu/ton, 1.94% S,
6.9% Ash, 2.94 lb. SO₂/MMBtu, 4.6% Btu increase per unit
wt. on cleaning.
- 1.7 Coal Transportation: 745 miles, \$15.83/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 25 yrs.
remaining life, 7000 hrs./year, 1.3261 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity,
utilized 260 days/ yr. @ 13 hrs./day (38.58%
utilization), level payment amortization
- 1.11 Flue Gas Scrubber: 329 MW_e minimum requirement,
378 MW_e design size, \$MM 49.97 capital cost,
17.85% annual cap. chrg., \$MM 8,920 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 76% of flue gas scrubbed, 20% of full
scale reheat required, 490,000 MMBtu/yr. full reheat,
\$980,000/yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.10 for amortization,
\$3.52 for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$2.73/ton
\$20.00/ton, additional coal cost is \$3.64/ton
\$25.00/ton, additional coal cost is \$4.55/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.21/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$7.56
\$20.00/ton, total additional cost is: \$9.38
\$25.00/ton, total additional cost is: \$9.38
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
 - 2.2.1 Capital Contribution: \$6.73
 - 2.2.2 Fuel & Electricity Cost: \$0.93
 - 2.2.3 O&M Costs: \$0.44 raw materials (limestone), \$0.21 operating labor; \$1.73 maintenance; \$0.08 miscellaneous.
Total O&M cost per ton of coal burned = \$2.46.
 - 2.2.4 Flue Gas Reheat Cost: \$0.15
 - 2.2.5 Total FGD Cost Per Ton of Coal: \$10.27
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
 - 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$1.32/ton
\$40.00/ton, added coal value is \$1.76/ton
\$50.00/ton, added coal value is \$2.20/ton
 - 2.3.2 Transportation Cost Saving: \$0.70/ton
 - 2.3.3 Saving in Utility Ash Disposal Cost: \$0.28/ton
 - 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.04/ton
 - 2.3.5 Saving in Pension Fund Payment: \$0.06/ton
 - 2.3.6 Saving in Utility Maintenance Cost: \$1.00/ton

2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price is:

\$30.00/ton, the total benefit is \$3.40/ton

\$40.00/ton, the total benefit is \$3.84/ton

\$50.00/ton, the total benefit is \$4.28/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	14.43	13.99	13.55
of Raw Coal (Per Ton)	\$20	15.34	14.90	14.46
	\$25	16.25	15.81	15.37

2.4.2 Cost Per Million Btu Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	0.55	0.53	0.51
of Raw Coal (Per Ton)	\$20	0.58	0.56	0.55
	\$25	0.62	0.60	0.58

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CASE NUMBER: 11B

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Concord, New Hampshire
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Pennsylvania
County: Greene Coalbed: Sewickley
- 1.5 Raw Coal:
3.26% S, 10.8% Ash 25.23 MMBtu/ton 5.17 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500MW_e,
25 yrs. remaining life,
7000 hrs./year,
1.3871 MMtons/yr.
- 1.7 Flue Gas Scrubber:
427 MW_e minimum requirement,
491 MW_e design size, \$MM 70.82 capital cost,
17.85% annual cap. chrg., \$MM 12.641 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
99% of flue gas scrubbed,
97% of full scale reheat required,
490,000 MMBtu/yr. full reheat \$980,000/yr.
for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$9.11
- 2.2 Fuel & Electricity Cost: \$1.21
- 2.3 O&M Costs:
\$0.97 raw materials (limestone),
\$0.20 operating labor;

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\$2.35 maintenance;

\$0.10 miscellaneous.

Total O&M cost per ton of coal burned = \$3.62.

2.4 Flue Gas Reheat Cost: \$0.69

2.5 Total FGD Cost Per Ton of Coal: \$14.63

2.6 FGD Cost per MMBtu: \$0.58

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CASE NUMBER: 11C

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Concord, New Hampshire
- 1.2 Emission Standard: Existing Plant, 1.5 lb of S per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: Pennsylvania
County: Greene Coalbed: Sewickley
- 1.5 Raw Coal: 3.26% S, 10.8% Ash, 25.23 MMBtu/ton,
5.17 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 64.6% cleaning plant wt. yield, 88.5%
cleaning plant Btu recovery, 26.39 MMBtu/ton, 1.94% S,
6.9% Ash, 2.94 lb. SO₂/MMBtu, 4.6% Btu increase per unit
wt. on cleaning.
- 1.7 Coal Transportation: 745 miles, \$15.83/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 15 yrs.
remaining life, 5000 hrs./year, 0.9472 MMtons coal yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$20,000/ton/hr. input capacity,
utilized 260 days/ hr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 0 MW_e minimum requirement, 0 MW_e
design size, \$MM - capital cost - % annual cap.chrg.,
\$MM cap. chrg./yr.
- 1.12 Flue Gas Reheat: 0% of flue gas scrubbed, 0% of full
scale reheat required, MMBtu full reheat
\$ /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$1.10 for amortization, \$3.52 for
O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$2.73/ton
\$20.00/ton, additional coal cost is \$3.64/ton
\$25.00/ton, additional coal cost is \$4.55/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.21/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is: \$7.56
\$20.00/ton, total additional cost is: \$8.47
\$25.00/ton, total additional cost is: \$9.38
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$ (FGD not required)
- 2.2.2 Fuel & Electricity Cost:
- 2.2.3 O&M Costs: \$ raw materials (limestone),
\$ operating labor; \$ maintenance;
\$ miscellaneous. Total O&M cost per ton of coal burned = \$
- 2.2.4 Flue Gas Reheat Cost: \$ -0-
- 2.2.5 Total FGD Cost Per Ton of Coal: \$
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
\$30.00/ton, added coal value is \$1.32/ton
\$40.00/ton, added coal value is \$1.76/ton
\$50.00/ton, added coal value is \$2.20/ton
- 2.3.2 Transportation Cost Saving: \$0.70/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.28/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.04/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.06/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$1.00/ton

2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price is:

\$30.00/ton, the total benefit is \$3.40/ton

\$40.00/ton, the total benefit is \$3.84/ton

\$50.00/ton, the total benefit is \$4.28/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price.

The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	4.16	3.72	3.28
of Raw Coal (Per Ton)	\$20	5.07	4.63	4.19
	\$25	5.98	5.54	5.10

2.4.2 Cost Per Million Btu Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	0.16	0.14	0.12
of Raw Coal (Per Ton)	\$20	0.19	0.18	0.16
	\$25	0.23	0.21	0.19

CASE NUMBER: 11D

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Concord, New Hampshire
- 1.2 Emission Standard: Existing Plant, 1.5 lb of S per MMBtu
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: Pennsylvania
County: Greene Coalbed: Sewickley
- 1.5 Raw Coal:
3.26% S 10.8% Ash 25.23 MMBtu/ton 5.17
lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
15 yrs. remaining life,
5000 hrs./year,
0.9908 MMtons/yr.
- 1.7 Flue Gas Scrubber:
233 MW_e minimum requirement,
267 MW_e design size, \$MM 54.71 capital cost,
20.12% annual cap. chrg., \$MM 11.008 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
54% of flue gas scrubbed,
0% of full scale reheat required,
MMBtu/yr. full reheat \$ - /yr.
for full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$11.11
- 2.2 Fuel & Electricity Cost: \$0.66
- 2.3 O&M Costs: \$
\$0.53 raw materials (limestone),
\$0.28 operating labor;

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\$2.54 maintenance;

\$0.05 miscellaneous.

Total O&M cost per ton of coal burned = \$3.40

2.4 Flue Gas Reheat Cost: \$

2.5 Total FGD Cost Per Ton of Coal: \$15.17

2.6 FGD Cost per MMBtu: \$0.60

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CASE NUMBERS: 12A, 12B, 12C, and 12D

Coal Source Area: Marion County, West Virginia

Coal Use Area: Dickerson (Montgomery County), Maryland

CASE NUMBER: 12A

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Dickerson (Montgomery County), Maryland
- 1.2 Emission Standard: New Plant, 1.2 lb SO₂ per MMBtu
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: West Virginia
County: Marion Coalbed: Pittsburgh
- 1.5 Raw Coal: 3.71% S, 10.5% Ash, 25.56 MMBtu/ton,
5.81 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 87% cleaning plant wt. yield, 93% cleaning
plant Btu recovery, 27.32 MMBtu/ton, 2.02% S, 5.4% Ash,
2.96 lb. SO₂/MMBtu, 6.9% Btu increase per unit wt. on
cleaning.
- 1.7 Coal Transportation: 245 miles, \$11.22/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 25 yrs.
remaining life, 7,000 hrs./year, 1.2811 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$17,150/ton/hr. input capacity,
utilized 260 days/ yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 330MW_e minimum requirement,
380 MW_e design size, \$MM 50.64 capital cost, 17.85% annual
cap. chrg., \$MM 9,039 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 75% of flue gas scrubbed, 20% of full
scale reheat required, 490,000 MMBtu/yr. full reheat,
\$980,000/yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$0.92 for amortization, \$3.43 for
O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal.
When Mine Operator's Coal Cost is:
\$15.00/ton, additional coal cost is \$2.24/ton
\$20.00/ton, additional coal cost is \$2.99/ton
\$25.00/ton, additional coal cost is \$3.74/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.18/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$15.00/ton, total additional cost is \$6.77
\$20.00/ton, total additional cost is \$7.52
\$25.00/ton, total additional cost is \$8.27
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$7.06
- 2.2.2 Fuel & Electricity Cost: \$0.93
- 2.2.3 O&M Costs: \$0.46 raw materials (limestone), \$0.22 operating labor; \$1.82 maintenance; \$0.08 miscellaneous.
Total O&M cost per ton of coal burned = \$2.58
- 2.2.4 Flue Gas Reheat Cost: \$0.15
- 2.2.5 Total FGD Cost Per Ton of Coal: \$10.72
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price is:
\$30.00/ton, added coal value is \$1.94/ton
\$40.00/ton, added coal value is \$2.58/ton
\$50.00/ton, added coal value is \$3.23/ton
- 2.3.2 Transportation Cost Saving: \$0.72/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$0.38/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.05/ton
- 2.3.5 Saving in Pension Fund Payment: \$0.09/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$1.29/ton

2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price is:

\$30.00/ton, the total benefit is \$4.47/ton

\$40.00/ton, the total benefit is \$5.11/ton

\$50.00/ton, the total benefit is \$5.76/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	13.02	12.38	11.73
	\$20	13.77	13.13	12.48
	\$25	14.52	13.88	13.23

2.4.2 Cost Per Million Btu Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost of Raw Coal (Per Ton)	\$15	0.48	0.45	0.43
	\$20	0.50	0.48	0.46
	\$25	0.53	0.51	0.48

CASE NUMBER: 12B

1.0 CASE CONDITIONS

1.1 Coal Use Area: Dickerson (Montgomery), Maryland

1.2 Emission Standard: New Plant, 1.2 lb of SO₂ per MMBtu

1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)

1.4 Origin of Coal: State: West Virginia

County: Marion Coalbed: Pittsburgh

1.5 Raw Coal:

3.71% S 10.5% Ash 25.56 MMBtu/ton 5.81 lb SO₂/MMBtu

1.6 Assumed Electric Utility Plant: 500 MW_e,

25 yrs. remaining life,

7000 hrs./year,

1.3693 MMtons/yr.

1.7 Flue Gas Scrubber:

* 441 MW_e minimum requirement,

507 MW_e design size, \$MM capital cost,

17.85% annual cap. chrg., \$MM 13.404 cap. chrg./yr.

1.8 Flue Gas Reheat:

100% of flue gas scrubbed,

100% of full scale reheat required,

490,000 MMBtu/yr. full reheat \$980,000/yr. cost for full reheat.

2.0 FGD COSTS PER TON OF CLEANED COAL BURNED

2.1 Capital Contribution: \$9.79

2.2 Fuel & Electricity Cost: \$1.22

2.3 O&M Costs:

\$1.11 raw materials (limestone),

\$0.21 operating labor;

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\$2.52 maintenance;

\$0.10 miscellaneous.

Total O&M cost per ton of coal burned = \$3.94.

2.4 Flue Gas Reheat Cost: \$0.72

2.5 Total FGD Cost Per Ton of Coal: \$15.67

2.6 FGD Cost Per MMBtu: \$0.61

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CASE NUMBER: 12C

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Dickerson (Montgomery County), Maryland
- 1.2 Emission Standard: Existing Plant, 1 percent S by weight
- 1.3 SO₂ Control Method: Combined use of coal cleaning & FGD
- 1.4 Origin of Coal: State: West Virginia
County: Marion Coalbed: Pittsburgh
- 1.5 Raw Coal: 3.71% S, 10.5% Ash, 25.56 MMBtu/ton,
5.81 lb. SO₂/MMBtu
- 1.6 Cleaned Coal: 87% cleaning plant wt. yield, 93% cleaning
plant Btu recovery, 27.32 MMBtu/ton, 2.02% S, 5.4% Ash,
2.96 lb. SO₂/MMBtu, 6.9% Btu increase per unit wt. on
cleaning.
- 1.7 Coal Transportation: 245 miles, \$11.22/ton
- 1.8 Assumed Electric Utility Plant: 500 MW_e, 15 yrs.
remaining life, 5000 hrs./year, 0.9151 MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$7.00/ton
- 1.10 Coal Cleaning Plant: \$17,150/ton/hr. input capacity,
utilized 260 days/ yr. @ 13 hrs./day (38.58% utilization),
level payment amortization
- 1.11 Flue Gas Scrubber: 281 MW_e minimum requirement,
323 MW_e design size, \$MM 55.67 capital cost, 20.12%
annual cap. chrg., \$MM 11.201 cap. chrg./yr.
- 1.12 Flue Gas Reheat: 65% of flue gas scrubbed, 0% of full
scale reheat required, - MMBtu/yr. full reheat,
\$ - /yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$0.92 for amortization,
\$3.43 for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal. When Mine Operator's Coal Cost is:
 - \$15.00/ton, additional coal cost is \$2.24/ton
 - \$20.00/ton, additional coal cost is \$2.99/ton
 - \$25.00/ton, additional coal cost is \$3.74/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$0.18/ton
- 2.1.4 Total Differential Cost to Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
 - \$15.00/ton, total additional cost is: \$6.77
 - \$20.00/ton, total additional cost is: \$7.52
 - \$25.00/ton, total additional cost is: \$8.27
- 2.2 Flue Gas Desulfurization Costs Per Ton of Cleaned Coal Burned
 - 2.2.1 Capital Contribution: \$12.24
 - 2.2.2 Fuel & Electricity Cost: \$0.79
 - 2.2.3 O&M Costs: \$0.39 raw materials (limestone), \$0.31 operating labor; \$2.80 maintenance; \$0.07 miscellaneous. Total O&M cost per ton of coal burned = \$3.57.
 - 2.2.4 Flue Gas Reheat Cost: \$-0-
 - 2.2.5 Total FGD Cost Per Ton of Coal: \$16.60
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
 - 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is:
 - \$30.00/ton, added coal value is \$1.94/ton
 - \$40.00/ton, added coal value is \$2.58/ton
 - \$50.00/ton, added coal value is \$3.23/ton
 - 2.3.2 Transportation Cost Saving: \$0.72/ton
 - 2.3.3 Saving in Utility Ash Disposal Cost: \$0.38/ton
 - 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$0.05/ton
 - 2.3.5 Saving in Pension Fund Payment: \$0.09/ton
 - 2.3.6 Saving in Utility Maintenance Cost: \$1.29/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B.Mine Price is:

\$30.00/ton, the total benefit is \$4.47/ton

\$40.00/ton, the total benefit is \$5.11/ton

\$50.00/ton, the total benefit is \$5.76/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall costs are:

2.4.1 Cost Per Ton of Coal Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	18.90	18.26	17.61
of Raw Coal (Per Ton)	\$20	19.65	19.01	18.36
	\$25	20.40	19.76	19.11

2.4.2 Cost Per Million Btu Burned To Meet Emission StandardF.O.B. Mine Raw Coal Price (Per Ton)

		<u>\$30</u>	<u>\$40</u>	<u>\$50</u>
Mine Operator's Cost	\$15	0.69	0.67	0.65
of Raw Coal (Per Ton)	\$20	0.72	0.70	0.67
	\$25	0.74	0.72	0.70

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CASE NUMBER: 12D

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: Dickerson (Montgomery County), Maryland
- 1.2 Emission Standard: Existing Plant, 1 percent S by weight
- 1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)
- 1.4 Origin of Coal: State: West Virginia
County: Marion Coalbed: Pittsburgh
- 1.5 Raw Coal:
3.71% S 10.5% Ash 25.56 MMBtu/ton 5.81 lb SO₂/MMBtu
- 1.6 Assumed Electric Utility Plant: 500 MW_e,
15 years. remaining life,
5000 hrs./year,
0.9781 MMtons/yr.
- 1.7 Flue Gas Scrubber:
406 MW_e minimum requirement,
467 MW_e design size, \$MM 88.93 capital cost,
20.12% annual cap. chrg., \$MM 17,893 cap. chrg./yr.
- 1.8 Flue Gas Reheat:
94% of flue gas scrubbed,
80% of full scale reheat required,
350,000 MMBtu/yr. full reheat, \$700,000/yr. for
full reheat.
- 2.0 FGD COSTS PER TON OF CLEANED COAL BURNED
- 2.1 Capital Contribution: \$18.29
- 2.2 Fuel & Electricity Cost: \$1.15
- 2.3 O&M Costs:
\$1.05 raw materials (limestone),
\$0.29 operating labor;

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\$4.18 maintenance;

\$0.09 miscellaneous.

Total O&M cost per ton of coal burned = \$5.61

2.4 Flue Gas Reheat Cost: \$0.57

2.5 Total FGD Cost Per Ton of Coal: \$25.62

2.6 FGD cost per MMBtu: \$1.00

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APPENDIX B
COAL PREPARATION PLANT O&M COST
ESTIMATE DEVELOPMENT
(BASED ON REFERENCE 4)

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Coal Preparation Plant O&M Cost
Estimate Development

The cleaning plant Operation and Maintenance (O&M) cost estimate is based on Reference 4. Even though the makeup of the Reference 4 plants may vary from that specified in Section 3.3 (of this report) it is estimated that the cost of labor, maintenance, supplies, etc. would be essentially equivalent.

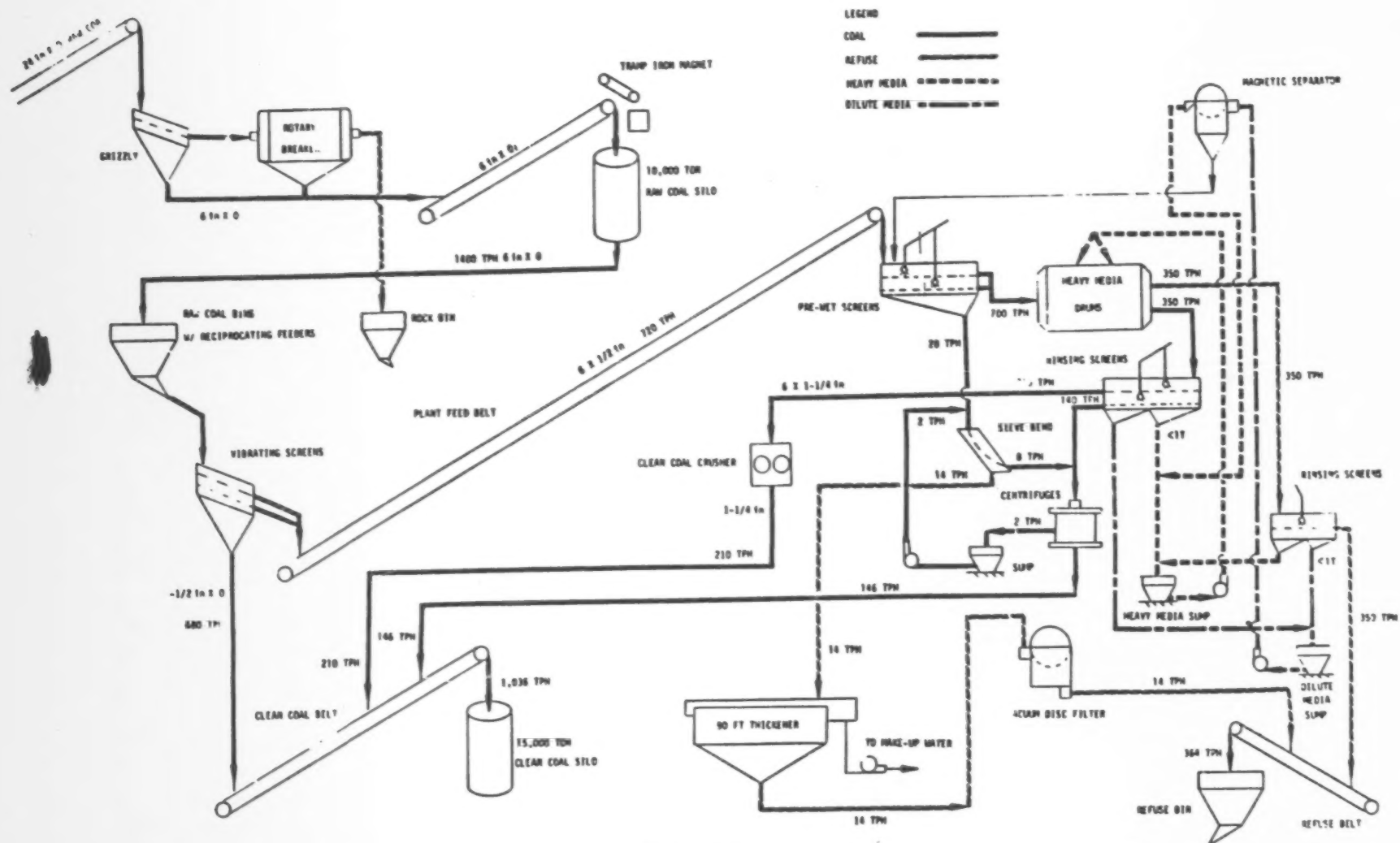
The cleaning plant O&M costs are provided in terms of cost per ton of coal input to the cleaning plant. The cost per ton of cleaned coal is simply equal to:

$$\frac{\text{O\&M cost per ton of raw coal}}{\text{cleaning plant weight yield (decimal value)}}$$

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FIGURE B-1
HEAVY MEDIA PROCESS
PREPARATION PLANT FLOW SHEET (EXAMPLE 5, REFERENCE 4)



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Table B-1
Heavy Media Process - O&M Cost
(Based on Example 5 of Reference 4)

<u>Cost Category</u>	<u>Cost Per Raw Ton w/29.68% Plant Util. ^a</u>	<u>Cost Per Raw Ton w/32.65% Plant Util. ^b</u>
Labor -		
Supervisory (Non Union)	\$0.148	\$0.135
Operating (Union)	0.360	0.327
Maintenance (Union)	0.254	0.231
Overhead -		
Non-Union Benefits - Includes Payroll Taxes, Group Life & Medical Insurance, Pension Fund, etc.	0.030	0.027
Union Benefits - Includes Payroll Taxes, Welfare Fund, Vacations, Holidays, Clothing Allowance, etc.	0.184	0.167
Other	0.112	0.112
Supplies -		
Operating - Magnetite, Flocculants, and clay settler accounts for 22%	0.610	0.610
Maintenance - Equipment repair, etc.	0.504	0.504
Electricity	<u>0.165</u>	<u>0.165</u>
O&M Cost (as of 12/77)	\$2.37	\$2.278

Estimated O&M cost per ton of raw coal with 32.65% cleaning plant utilization with cost updated to 1/1/81 (as based on BLS indexes) = \$3.18.

^a Reference 4 values

^b Estimated values to reflect cleaning plant operating 220 days/year at 13 hours/day (32.65% utilization)

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FIGURE B-2

HEAVY MEDIA PROCESS - COMPLEX

PREPARATION PLANT FLOW SHEET (EXAMPLE 6, REFERENCE 4)

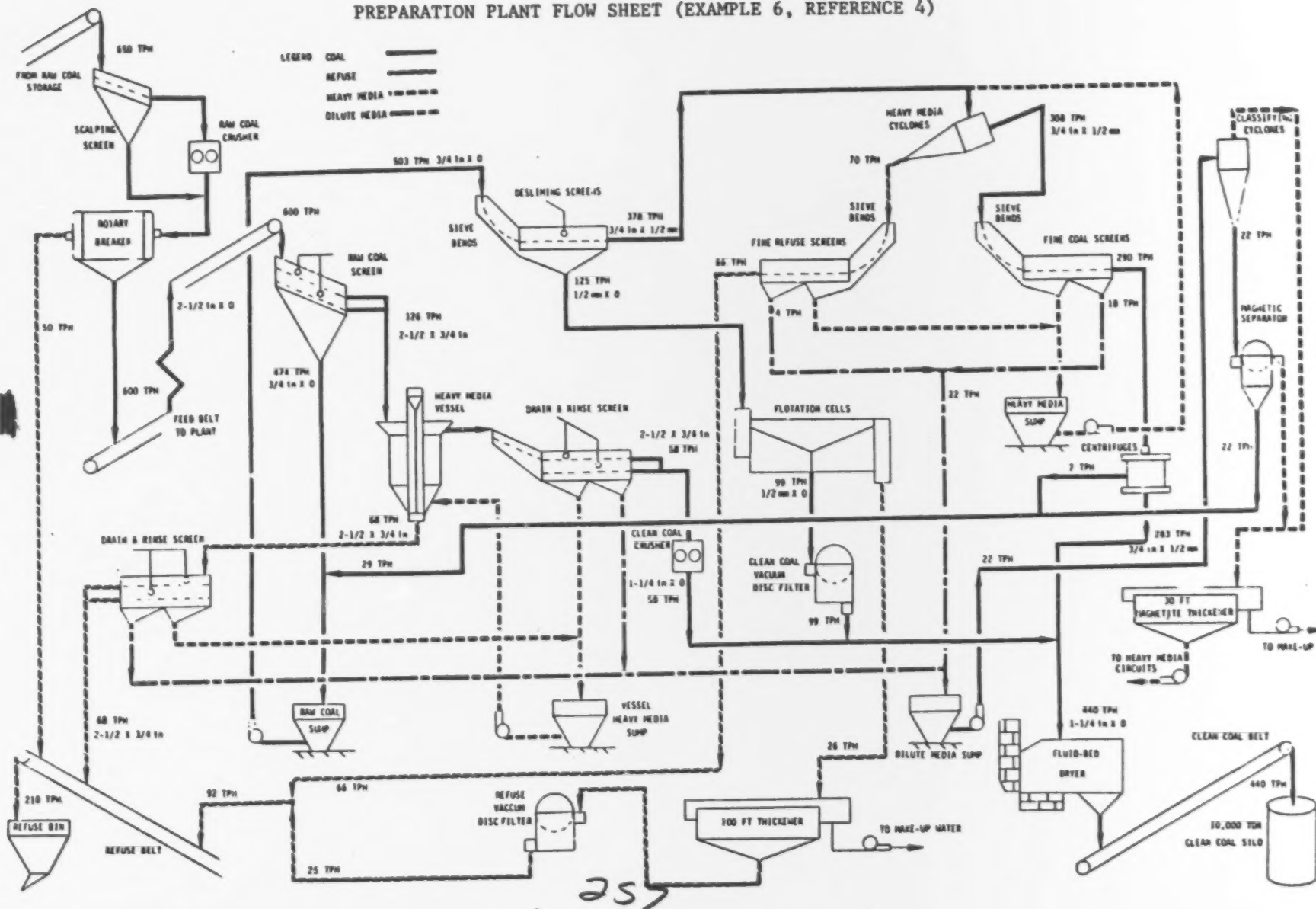


Table B-2
Heavy Media Process - O&M Cost
(Based on Example 6 of Reference 4)

<u>Cost Category</u>	<u>Cost Per Raw Ton w/29.68% Plant Util. ^a</u>	<u>Cost Per Raw Ton w/32.65% Plant Util. ^b</u>
Labor -		
Supervisory (Non Union)	\$0.099	\$0.090
Operating & Maintenance (Union)	0.638	0.580
Overhead -		
Fringe Benefits -		
25% Non-Union	0.025	0.023
20% Union	0.128	0.116
Other -		
Includes Workmen's Compensation		
Insurance, Payroll Taxes,		
Welfare Fund, etc.	0.213	0.204
Supplies -		
Operating	0.169	0.169
Maintenance & Other	0.242	0.242
Thermal Dryer Fuel -		
Based upon 7.0 Tons/hr coal		
consumption & cost of coal		
\$20/Ton	0.233	0.233
Cleaning Plant Repair Parts	0.147	0.147
Electricity (Large Thermal Dryer)	<u>0.334</u>	<u>0.334</u>
O&M Cost (as of 12/77)	\$2.23	\$2.138

Estimated O&M Cost per ton of raw coal with 32.65% cleaning plant utilization with cost updated to 1/1/81 (as based on BLS indexes) = \$2.98.

^a Reference 4 values

^b Estimated values to reflect cleaning plant operating 220 days/year at 13 hours/day (32.65% utilization)

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FIGURE B-3
HEAVY MEDIA PROCESS - COMPLEX
PREPARATION PLANT FLOW SHEET (EXAMPLE 7, REFERENCE 4)

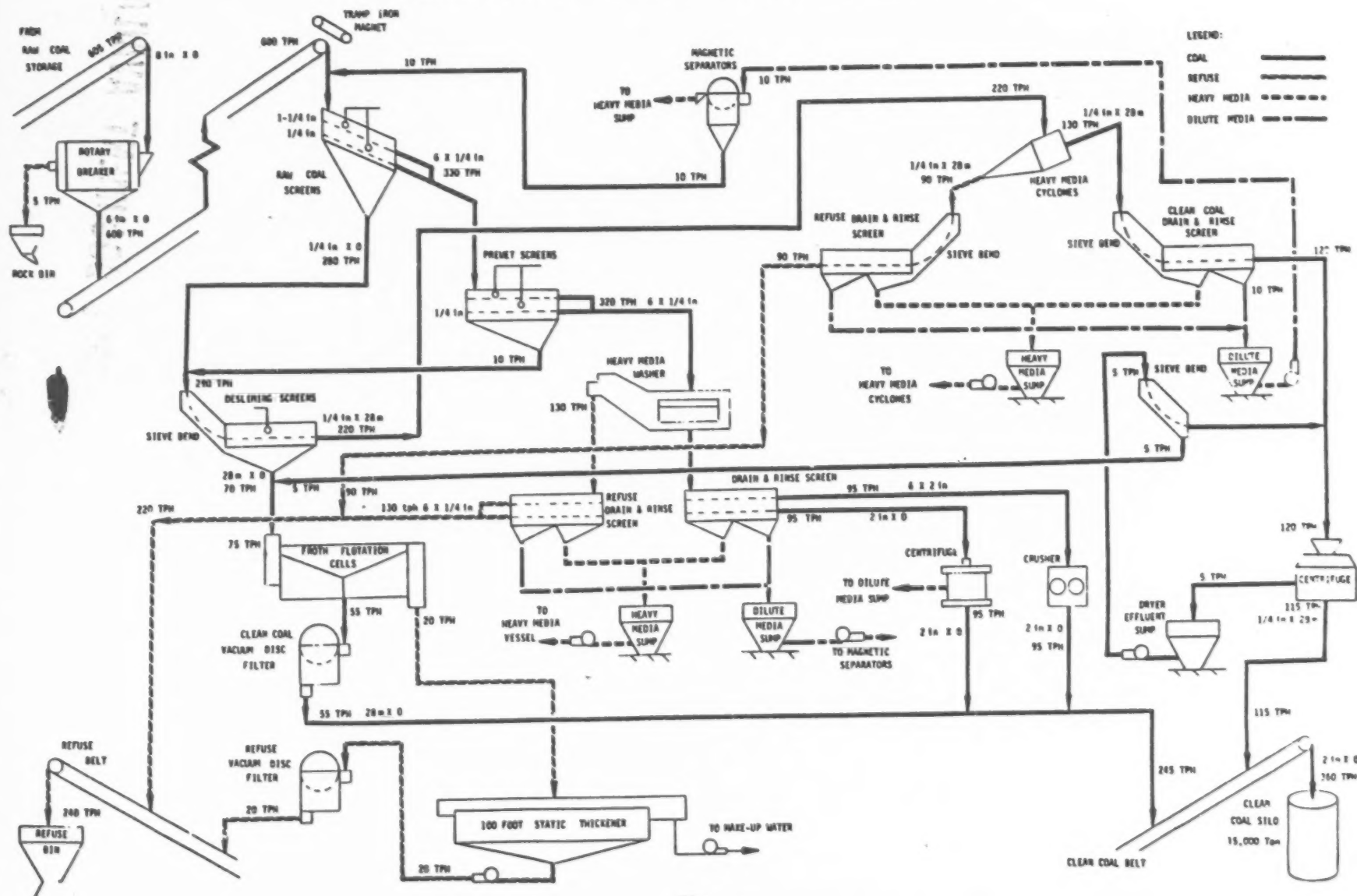


Table B-3
Heavy Media Process - O&M Cost
(Based on Example 7 of Reference 4)

<u>Cost Category</u>	<u>Cost Per Raw Ton w/29.68% Plant Util.^a</u>	<u>Cost Per Raw Ton w/32.65% Plant Util.^b</u>
Labor -		
Supervisory (Non-Union)	\$0.058	\$0.053
Operating & Maintenance (Union)	0.211	0.192
Overhead -		
Fringe Benefits -		
25% Non-Union	0.014	0.013
21% Union	0.044	0.040
Other -		
Includes Welfare Fund, Payroll Taxes, Property Taxes, Insurance, etc.	0.060	0.060
Supplies -		
Operating -		
Magnetite	0.055	0.055
Other	0.307	0.307
Maintenance	0.092	0.092
Major Maintenance -		
Scheduled repairs and plant improvements	0.051	0.051
Electricity	0.090	0.090
Subcontract services for major equipment repairs & miscellaneous expenses	<u>0.289</u>	<u>0.289</u>
O&M Cost (as of 12/77)	\$1.27	\$1.242

With 32.65% plant util. and adding \$0.30 for dryer, \$0.30 for additional maintenance, \$0.10 for dryer associated labor, and \$0.057 additional benefits we have a 12/77 O&M cost of \$2.00 per ton of raw coal. With cost updated to 1/1/81 (as based on BLS indexes), cost estimate = \$2.79 per raw ton of coal.

^a Reference 4 values

^b Estimated values to reflect cleaning plant operating 220 days at 13 hours/day (32.65% utilization)

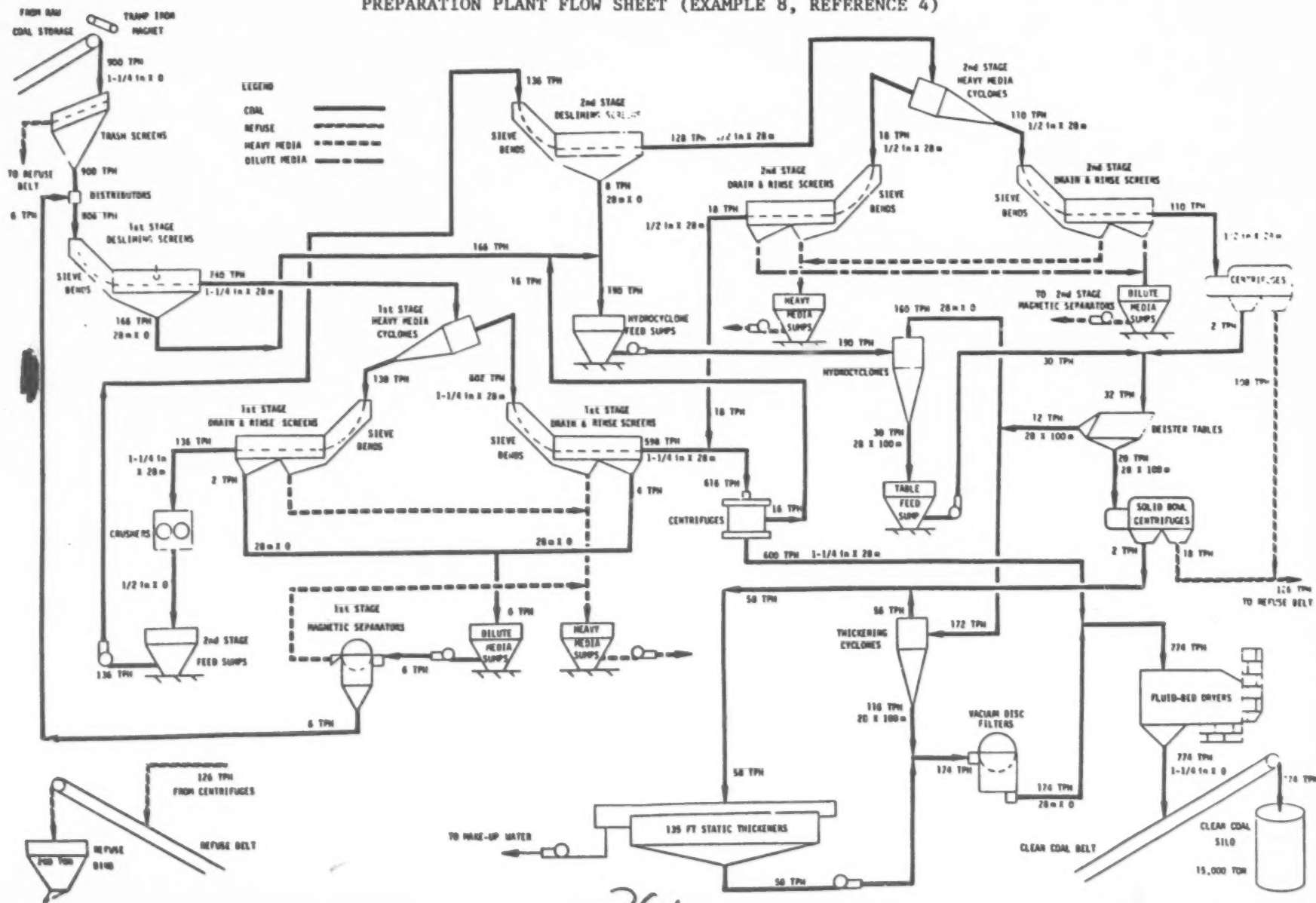
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FIGURE B-4

HEAVY MEDIA PROCESS - COMPLEX

PREPARATION PLANT FLOW SHEET (EXAMPLE 8, REFERENCE 4)



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Table B-4
Heavy Media Process - O&M Cost
(Based on Example 8 of Reference 4)

<u>Cost Category</u>	<u>Cost Per Raw Ton based on 50% plant util.</u>
Labor -	
Supervisory (Non-Union)	\$0.035
Operating & Maintenance (Union)	0.267
Overhead -	
Includes Payroll Taxes, Vacation & Holiday Pay, Welfare Fund, Taxes, Insurance, etc.	0.196
Supplies -	
Operating	0.249
Maintenance - Includes scheduled major repair and replacements	0.529
Thermal Dryer Fuel -	
Based upon 12.5 tons/hr coal consumption & cost of coal \$20/ton	0.278
Electricity	0.456
Other	<u>0.087</u>
	\$2.10

Estimated O&M cost per ton of raw coal with 32.65% cleaning plant utilization with cost updated to 1/1/81 (as based on BLS indexes) = \$2.93 per ton of raw coal. It is assumed that for this case the labor cost per ton would essentially be constant in going from a 50% to a 32.65% utilization (i.e. a reduction in number of shifts).

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APPENDIX C
COAL TRANSPORTATION

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RAIL TRANSPORTATION OF COAL

The great preponderance of coal - over 60 percent - moves by rail. The railroads derive more revenue from it than any other commodity. The hauling of bituminous coal has long been the single most important commodity for Eastern railroads. During 1978, on a nationwide basis, the railroads carried over 400 million tons of coal.

Types of Rail Freight Rates on Bituminous Coal

Bituminous coal is rated class 17-1/2 in the governing Uniform ICC Freight Classification. However, extremely little, if any, coal moves at class rates, although at some shipping points class rates are the only rates available. For example, effective June 28, 1974, a unit-train rate applicable on bituminous coal over the lines of the Kansas City Southern Railway Company from Heavener, Oklahoma, to Steeltown, Texas, was canceled. The cancellation notice provided that class rates would apply.

There are numerous types of commodity rates applying on bituminous coal. Those that are necessary for understanding the freight rate structure follow:

Single-car rates, multiple-car rates, trainload rates, and unit-train rates are those based essentially on the number of cars used. In many instances the rates are not listed as single-car, multiple-car, trainload, or unit-train rates, and the terminology is not always uniformly defined by carriers and shippers. A

single-car rate is one that is published based on tonnage requiring the use of one car only. This tonnage is usually 100 tons or less, and is frequently based on the marked capacity of the car. Multiple-car rates are rates based on a sufficient tonnage to require the use of two or more cars, moving from one point of origin to one point of destination at one time. A multiple-car rate differs from a trainload rate in that the required tonnage is less than the amount necessary to make up an entire trainload as hereafter defined. A frequently maintained condition for multiple-car rates is 1,500 tons. A trainload rate is a rate that is published based on a sufficient tonnage to make up an entire train, usually 5,000 tons or more. The railroad equipment is usually furnished by the carrier and the movement does not have a predetermined continuously scheduled cycle. A unit-train rate is one that is published to apply on traffic moving in a sufficient set number of railroad cars and a given number of motive units dedicated to one unit between one point of loading and one point of unloading and moving in continuously scheduled cycles. The cars may or may not be permanently coupled. The equipment and motive power are not taken out of the movement, and in a number of instances the cars are shipper-owned.

Annual volume and conditional rates are those based primarily on the stipulation of the movement of a stated tonnage over a specific time period. A frequent annual-volume requirement is that 1 million tons of bituminous coal be tendered during one calendar year. There are single-car annual-volume rates, multiple-car annual-volume rates, trainload annual-volume rates, and unit-train annual-volume rates, depending upon the conditions of the published tariff.

There are certain types of rates based substantially on geographic considerations. These include concentration rates, gathering rates, tidewater rates, export rates, river rates, lake-cargo rates, and refund rates. Concentration rates are rates in connection with which it is provided that coal may originate at

various separate mines, concentrated by the customer at one specific common point, thus permitting the movement of the cars beyond the concentration point in blocks so that from the place of concentration to the final destination the movement is multiple-car, trainload, or unit-train service. Gathering rates are rates from mines or stations to a concentration point such as Appalachia, Virginia, for rail movement beyond in multiple-car trainload, or unit-train service. Tidewater rates normally refer to rates applying on coal moved by rail from the Appalachian fields to the ports of New York, Philadelphia, Baltimore, and Hampton Roads, for movement beyond by water to destinations in the United States. At times the coal movements destined to Baltimore, and Hampton Roads, for export are referred to as "tidewater coal" or tidewater movements." This coal moves at export rates. An export rate is one specifically established for application on export traffic. River rates are those that are published on traffic having aprior or subsequent movement via barge. Lake-cargo rates are those that are published on traffic having a prior or subsequent movement over one or more of the Great Lakes. Under certain conditions, a refund is provided in the tariffs after traffic has moved from the lake ports and the specified conditions are met. In some instances, rates applicable to a specific movement may consist of more than one of these types of rates.

It is expected that in 1981 more than 85 percent of the domestic coal traffic will move under annual-volume, concentration, trainload, or unit-train concepts. Discussions of these rates follow.

The Annual-Volume and Concentration Rate Concepts

Annual volume rates have been used mainly as a competitive tool of the carriers in their efforts to thwart the use of alternative energy sources, such as natural gas, and the use of other forms of coal or energy transport, such as slurry pipelines or

high-voltage wires. Also, the annual-volume concept has sometimes been coupled with other transportation conditions designed to achieve economies in coal handling. In this way, the carriers have attempted to offset, to the extent possible, the effect of revenue losses from downward adjustments necessitated by competition.

Although the cost of large equipment exceeds that of smaller cars, there are savings in transportation effort flowing from the use of large cars. The principle involved is clear when assuming 100 tons of coal is being carried in one 100-ton car versus two 50-ton cars. The handling of one carload is saved, and the car miles are cut in half. Because the tare weight of a 100-ton car versus two 50-ton cars. The handling of one carload is saved, and the car miles are cut in half. Because the tare weight of a 100-ton car is less than that of two 50-ton cars, the amount of deadweight per ton of coal carried is reduced.

In addition to annual-volume provisions, the railroads have established rates substantially lower than their single-car rates when the customer concentrates shipments at a common point. This permits the movement of the cars beyond the concentration point in blocks, so that from the place of concentration to the final destination the movement is multiple-car, trainload, or unit-train service.

A relatively new concept in the distribution of coal by railroad in unit trains was put into operation in September 1966. One of the problems that develops in the inauguration of unit trains comes about by virtue of the fact that coal often originates at many small mines, no single one of which can produce and load out a trainload in one day. A past solution to this problem has been to store coal in large piles from which trainloads can be originated. But, coal does deteriorate to some extent when stored in the open. The loss of coal resulting from open-air storage has been found to make the construction of closed storage silos economically feasible.

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The concept is that coal from small-volume mines can be brought to the transloader in a gathering operation, making use of small hoppers and gondolas. The small equipment can be economically operated in a short-haul gathering function, whereas it is largely obsolete for long-haul transportation of volume movements. The cars feed the transloader silos. The silos in turn feed the unit train.

There is a definite difference between trainload and unit-train service. Although these terms are often loosely used to describe any trainload shipment of coal, the services involved are completely different. Some railroads operate trainloads, using ordinary equipment in single moves at random times without reference to any scheduled operation. This type of service should be called trainload, and the applicable rates referred to as trainload rates.

On the other hand, unit trains involve a shuttle service concept with the train operating on a predetermined schedule and in assigned equipment. Specifically, a unit train is a management technique that permits efficient planning through long-range contractual commitment of producer and consumer and dedication of the equipment. A unit train consists of a dedicated set of haulage equipment loaded at one origin, unloaded at one destination each trip, and moving in both directions on a predetermined schedule. Although the origin and destination are not necessarily the same for each trip, the shipment is never split for any trip.

In terms of the tariff, or freight rate, a unit train is not a unit train until so designated by the carrier. Thus, the success of a unit train depends on cooperation between shipper, carrier, and consumer. In fixing tariff rates, the lowest cost usually is realized when a unit train is limited to a single-line haul. When more than one carrier is involved, additional capital cost and additional operating costs are reflected in the tariff rates. The

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tariff rates specify the haulage cost to the consumer on a net ton basis. Three parties--the railroad, the producer, and the consumer--must negotiate the conditions and the rates (coal and transport) for unit-train service.

Bureau of Labor Statistics Index For The Transportation of Coal
by Rail

The Bureau of Labor Statistics (BLS) publishes a monthly price index for transportation of railroad freight. The index is designed to measure changes in prices of shipping goods by rail in the United States. It reflects the price changes for all railroad shipments.

The index is intended to measure "pure" price change between two periods of time; that is, to measure price changes not influenced by changes in quantity, shipping terms, type of service, product mix, or other factors. Therefore, identical shipments of commodities are used in the periods compared. For this purpose, the shipments included in the index are defined by precise specifications which incorporate the principal price-determining factors such as type of commodity, origin, destination, quantity, routing, service provided, and type of rail car. Thus, the prices used in the index conform with the concept of the railroad's price for shipping a fixed set of commodities under specified conditions. The prices used to calculate the index are the rates in effect on the 15th of each month for identical shipments of commodities.

The railroads are required by law to establish rates that are just and reasonable, publish them, and adhere to them. These rates, and changes in them, covering both interstate and intrastate shipments, are published by the railroads in schedules referred to as tariffs. The regulations governing the publication of inter-

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state rail freight tariffs are prescribed by the Interstate Commerce Commission. There are approximately 45,000 tariffs in current use, containing millions of rates. Each month the tariff, applicable increase tariffs, and supplements are checked by the BLS for each shipment to determine the applicable rate as of the 15th of that month. This procedure was adopted to minimize the railroads' burden of reporting specific rates each month and to simplify quality control.

The detailed information necessary to select a sample of shipments to be priced is available on railroad waybills. A waybill moves with the shipment and contains all the information necessary for the railroads to transport a shipment and to prepare a bill. The information needed for the construction of the BLS index was abstracted from the waybills. The commodity shipped, origin, and destination of the shipment, railroads involved in the movement (routing), size of shipment, type of service provided, type of railcar used, and the rate at which the freight charge was calculated were obtained from each waybill used.

Based on information obtained from the BLS, it was estimated that since mid-1976 to January 1981, the average cost for shipping coal by rail increased 70 percent. The coal shipping values used in this study are based on mid-1976 values (per Reference 1) escalated by 70 percent.

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APPENDIX D
LIMESTONE FLUE GAS DESULFURIZATION
CAPITAL COST ESTIMATES

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TABLE D-1. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO₂ removal; pond disposal of waste solids)

	Investment, \$	% of total direct investment
<u>Direct Investment</u>		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	1,824,000	6.4
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	2,062,000	7.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,950,000	17.3
SO ₂ absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,458,000	33.2
Stack gas reheat (four indirect steam reheaters)	1,292,000	4.5
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	2,164,000	7.6
Subtotal	21,750,000	76.2
Services, utilities, and miscellaneous	1,305,000	4.6
Total process areas excluding pond construction	23,055,000	80.8
Pond construction	5,481,000	19.2
Total direct investment	28,536,000	100.0
<u>Indirect Investment</u>		
Engineering design and supervision	1,240,000	4.3
Architect and engineering contractor	274,000	1.0
Construction expense	3,915,000	13.7
Contractor fees	1,226,000	4.3
Total indirect investment	6,655,000	23.3
Contingency	7,038,000	24.7
Total fixed investment	42,229,000	148.0
<u>Other Capital Charges</u>		
Allowance for startup and modifications	3,675,000	12.9
Interest during construction	5,068,000	17.7
Total depreciable investment	50,972,000	178.6
Land	1,098,000	3.9
Working capital	1,013,000	3.5
Total capital investment	53,083,000	186.0

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F).

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

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TABLE D-2. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 2.0% S in coal;
90% SO₂ removal; pond disposal of waste solids)

	Investment, \$	% of total direct investment
<u>Direct Investment</u>		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	1,180,000	4.9
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,359,000	5.6
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,930,000	20.3
SO ₂ absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,420,000	38.7
Stack gas reheat (four indirect steam reheaters)	1,287,000	5.3
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,569,000	6.3
Subtotal	19,745,000	81.3
Services, utilities, and miscellaneous	1,185,000	4.9
Total process areas excluding pond construction	20,930,000	86.2
Pond construction	3,346,000	13.8
Total direct investment	24,276,000	100.0
<u>Indirect Investment</u>		
Engineering design and supervision	1,173,000	4.8
Architect and engineering contractor	268,000	1.1
Construction expense	3,474,000	14.3
Contractor fees	1,084,000	4.5
Total indirect investment	5,999,000	24.7
Contingency	6,055,000	24.9
Total fixed investment	36,330,000	149.6
<u>Other Capital Charges</u>		
Allowance for startup and modifications	3,298,000	13.6
Interest during construction	4,360,000	18.0
Total depreciable investment	43,988,000	181.2
Land	675,000	2.8
Working capital	848,000	3.5
Total capital investment	45,511,000	187.5

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

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TABLE D-3. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 1.4% S in coal;
90% SO₂ removal; pond disposal of waste solids)

	Investment, \$	% of total direct investment
<u>Direct Investment</u>		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	843,000	3.8
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	984,000	4.5
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,915,000	22.2
SO ₂ absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,392,000	42.5
Stack gas reheat (four indirect steam reheaters)	1,283,000	5.8
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,223,000	5.5
Subtotal	18,640,000	84.3
Services, utilities, and miscellaneous	1,118,000	5.1
Total process areas excluding pond construction	19,758,000	89.4
Pond construction	2,342,000	10.6
Total direct investment	22,100,000	100.0
<u>Indirect Investment</u>		
Engineering design and supervision	1,136,000	5.1
Architect and engineering contractor	264,000	1.2
Construction expense	3,238,000	14.7
Contractor fees	1,009,000	4.6
Total indirect investment	5,647,000	25.6
Contingency	5,549,000	25.1
Total fixed investment	33,296,000	150.7
<u>Other Capital Charges</u>		
Allowance for startup and modifications	3,095,000	14.0
Interest during construction	3,996,000	18.0
Total depreciable investment	40,387,000	182.7
Land	478,000	2.2
Working capital	769,000	3.5
Total capital investment	41,634,000	188.4

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

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TABLE D-4. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 0.8% S in coal;
90% SO₂ removal; pond disposal of waste solids)

	Investment, \$	% of total direct investment
<u>Direct Investment</u>		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	631,000	3.0
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	746,000	3.5
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	5,034,000	23.8
SO ₂ absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,628,000	45.4
Stack gas reheat (four indirect steam reheaters)	1,315,000	6.2
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	987,000	4.7
Subtotal	18,341,000	86.6
Services, utilities, and miscellaneous	1,101,000	5.2
Total process areas excluding pond construction	19,442,000	91.8
Pond construction	1,748,000	8.2
Total direct investment	21,190,000	100.0
<u>Indirect Investment</u>		
Engineering design and supervision	1,112,000	5.3
Architect and engineering contractor	262,000	1.2
Construction expense	3,142,000	14.8
Contractor fees	978,000	4.6
Total indirect investment	5,494,000	25.9
Contingency	5,337,000	25.2
Total fixed investment	32,021,000	151.1
<u>Other Capital Charges</u>		
Allowance for startup and modifications	3,027,000	14.3
Interest during construction	3,843,000	18.1
Total depreciable investment	38,891,000	183.5
Land	364,000	1.7
Working capital	740,000	3.5
Total capital investment	39,995,000	188.7

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

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TABLE D-5. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(1000-MW new coal-fired power unit, 3.5% S in coal;
90% SO₂ removal; pond disposal of waste solids)

	Investment, \$	% of total direct investment
<u>Direct Investment</u>		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, puller)	2,951,000	5.7
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	3,270,000	6.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	9,672,000	18.7
SO ₂ absorption (eight TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	18,443,000	35.7
Stack gas reheat (eight indirect steam reheaters)	2,519,000	4.9
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	3,090,000	6.0
Subtotal	39,945,000	77.3
Services, utilities, and miscellaneous	2,397,000	4.6
Total process areas excluding pond construction	42,342,000	81.9
Pond construction	9,357,000	18.1
Total direct investment	51,699,000	100.0
<u>Indirect Investment</u>		
Engineering design and supervision	1,814,000	3.5
Architect and engineering contractor	403,000	0.8
Construction expense	6,431,000	12.4
Contractor fees	1,925,000	3.7
Total indirect investment	10,573,000	20.4
Contingency	12,454,000	24.1
Total fixed investment	74,726,000	144.5
<u>Other Capital Charges</u>		
Allowance for startup and modifications	6,537,000	12.6
Interest during construction	8,967,000	17.4
Total depreciable investment	90,230,000	174.5
Land	1,844,000	3.6
Working capital	1,867,000	3.6
Total capital investment	93,941,000	181.7

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

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TABLE D-6. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(700-MW new coal-fired power unit, 3.5% S in coal;
90% SO₂ removal; pond disposal of waste solids)

	Investment, \$	% of total direct investment
<u>Direct Investment</u>		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, puller)	2,313,000	6.0
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	2,590,000	6.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	7,029,000	18.2
SO ₂ absorption (six TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	13,374,000	34.7
Stack gas reheat (six indirect steam reheaters)	1,824,000	4.7
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	<u>2,580,000</u>	<u>6.7</u>
Subtotal	29,710,000	77.0
Services, utilities, and miscellaneous	<u>1,783,000</u>	<u>4.6</u>
Total process areas excluding pond construction	31,493,000	81.6
Pond construction	<u>7,100,000</u>	<u>18.4</u>
Total direct investment	38,593,000	100.0
<u>Indirect Investment</u>		
Engineering design and supervision	1,538,000	4.0
Architect and engineering contractor	342,000	0.9
Construction expense	5,041,000	13.0
Contractor fees	<u>1,542,000</u>	<u>4.0</u>
Total indirect investment	8,463,000	21.9
Contingency	<u>9,411,000</u>	<u>24.4</u>
Total fixed investment	36,467,000	146.3
<u>Other Capital Charges</u>		
Allowance for startup and modifications	4,937,000	12.8
Interest during construction	<u>6,776,000</u>	<u>17.6</u>
Total depreciable investment	68,180,000	176.7
Land	1,408,000	3.6
Working capital	<u>1,379,000</u>	<u>3.6</u>
Total capital investment	70,967,000	183.9

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

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TABLE D-7. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(200-MW new coal-fired power unit, 3.5% S in coal;
90% SO₂ removal; pond disposal of waste solids)

	Investment, \$	% of total direct investment
<u>Direct Investment</u>		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	950,000	7.0
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,103,000	8.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	2,158,000	16.0
SO ₂ absorption (two TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	4,076,000	30.2
Stack gas reheat (two indirect steam reheaters)	556,000	4.1
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,135,000	9.9
Subtotal	10,178,000	75.4
Services, utilities, and miscellaneous	611,000	4.3
Total process areas excluding pond construction	10,789,000	79.9
Pond construction	2,717,000	20.1
Total direct investment	13,506,000	100.0
<u>Indirect Investment</u>		
Engineering design and supervision	943,000	7.0
Architect and engineering contractor	214,000	1.6
Construction expense	2,098,000	15.5
Contractor fees	654,000	5.1
Total indirect investment	3,949,000	29.2
Contingency	3,491,000	25.9
Total fixed investment	20,946,000	155.1
<u>Other Capital Charges</u>		
Allowance for startup and modifications	1,823,000	13.5
Interest during construction	2,514,000	18.6
Total depreciable investment	25,283,000	187.2
Land	354,000	4.1
Working capital	465,000	3.4
Total capital investment	26,302,000	194.7

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

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APPENDIX E
WASHABILITY CURVES OF
CONSIDERED COALS

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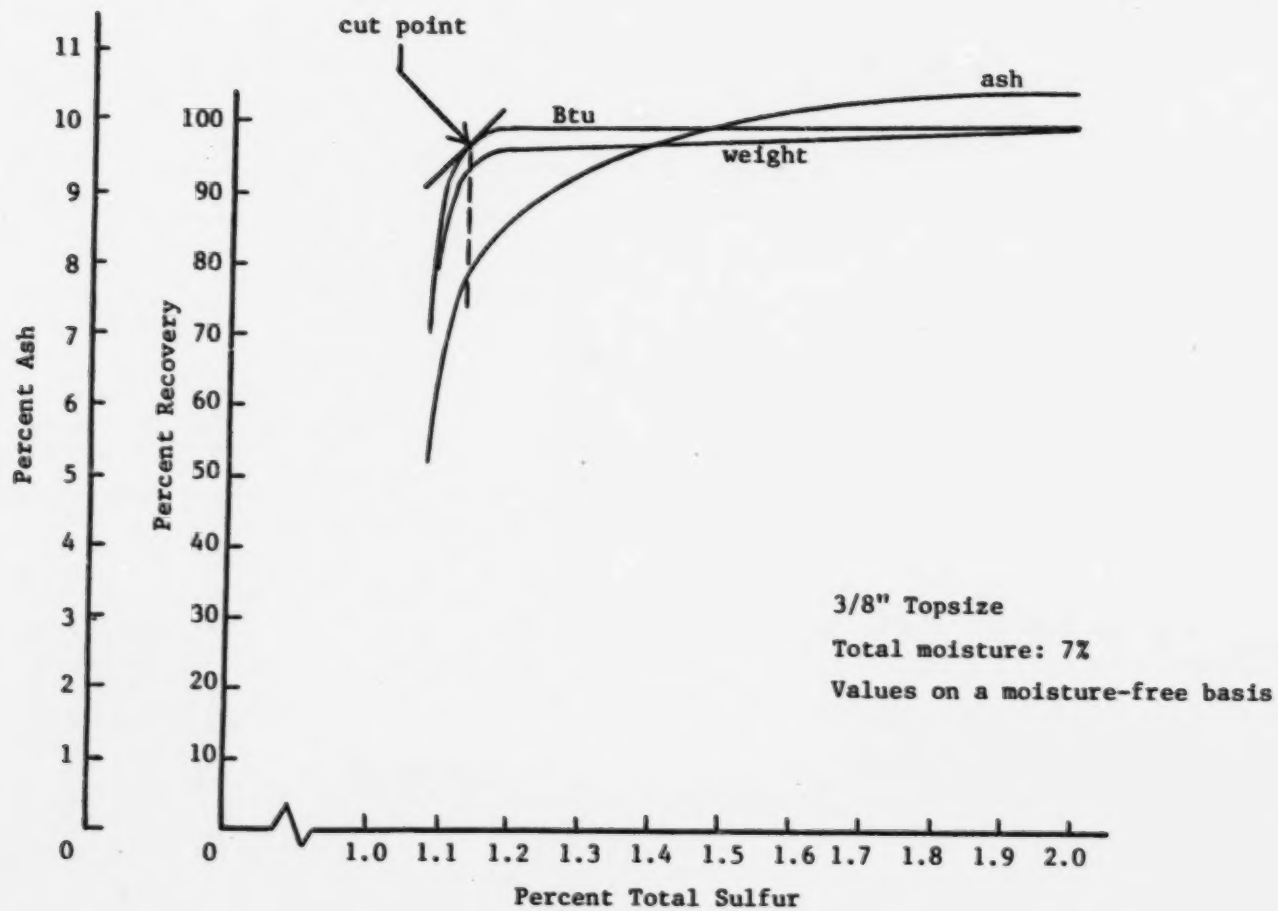


Figure E-1
Washability Curves For Case Studies 1A and 1C

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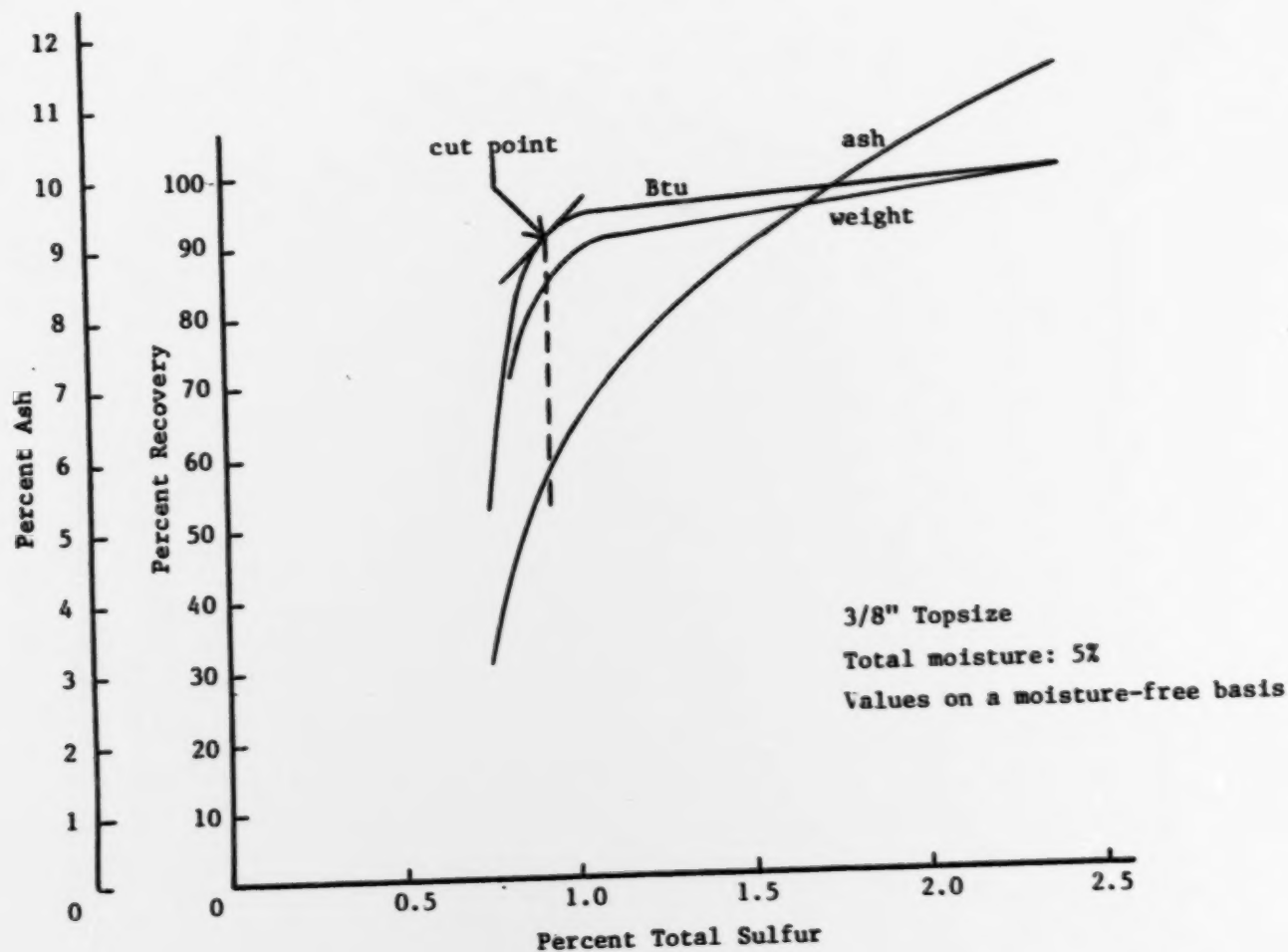


Figure E-2
Washability Curves For Cases 2A and 2C

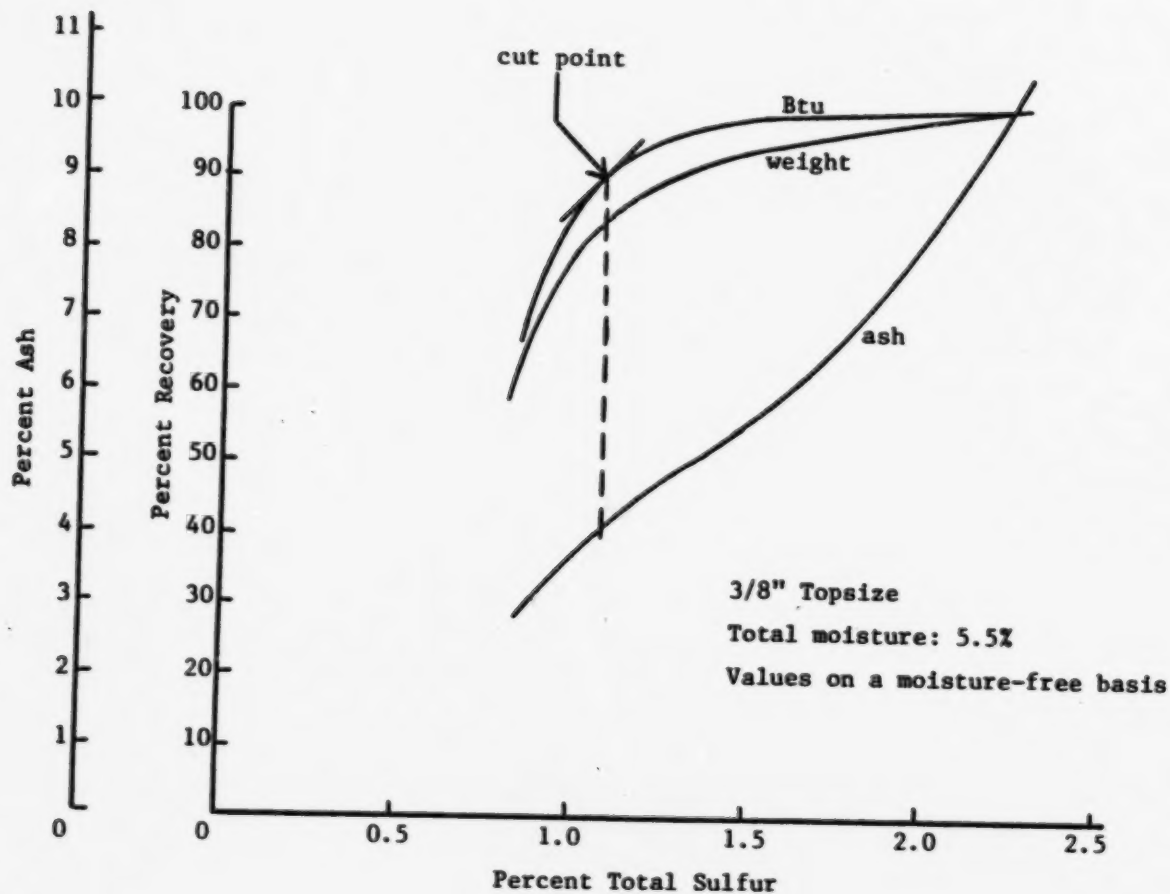


Figure E-3
Washability Curves For Cases 3A and 3C

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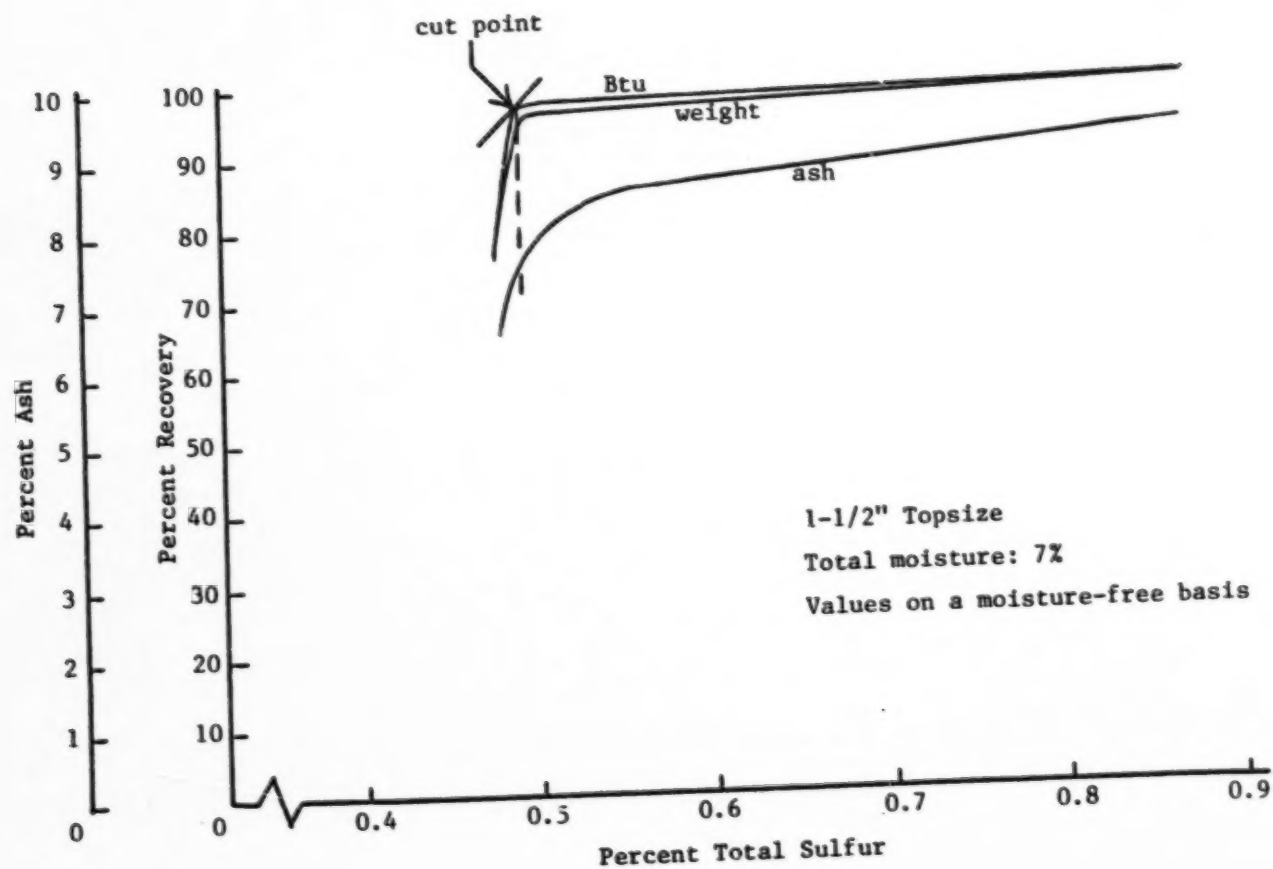


Figure E-4
Washability Curves For Cases 4A and 4C

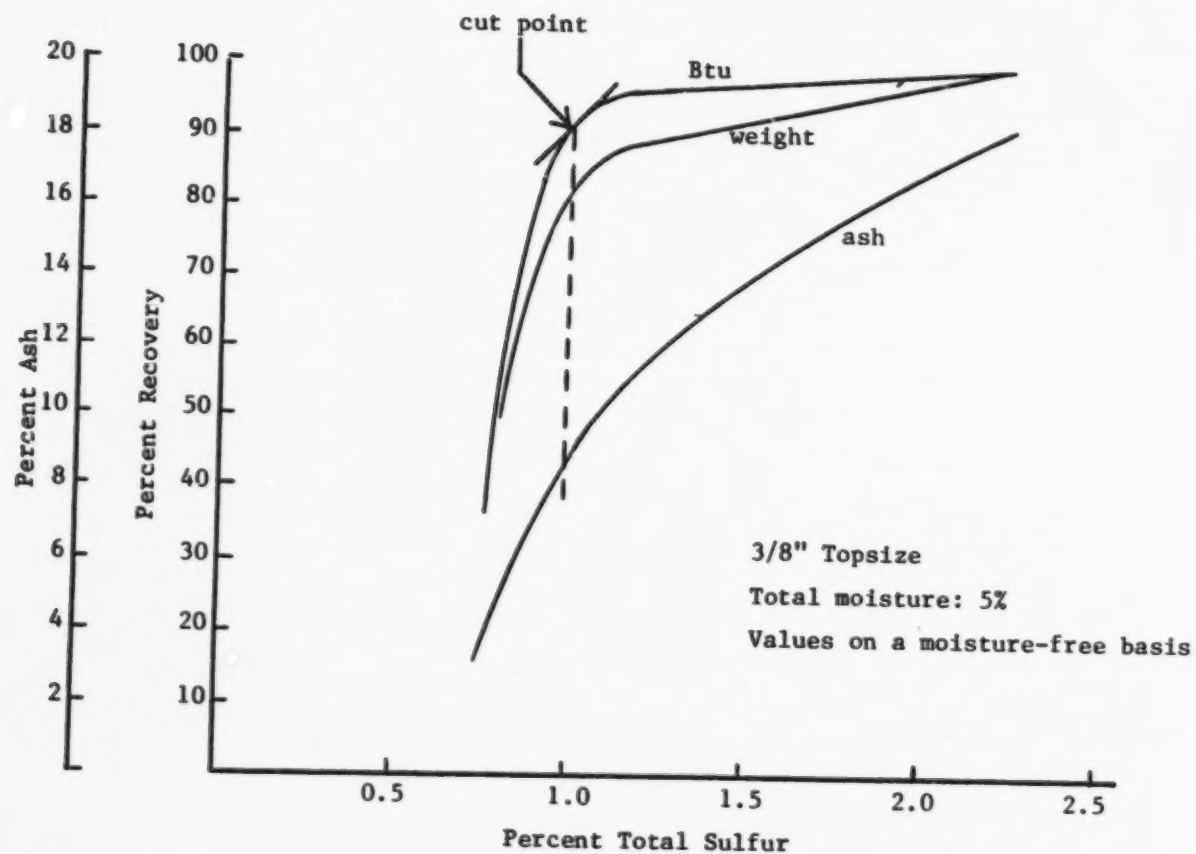


Figure E-5
Washability Curves For Cases 5A and 5C

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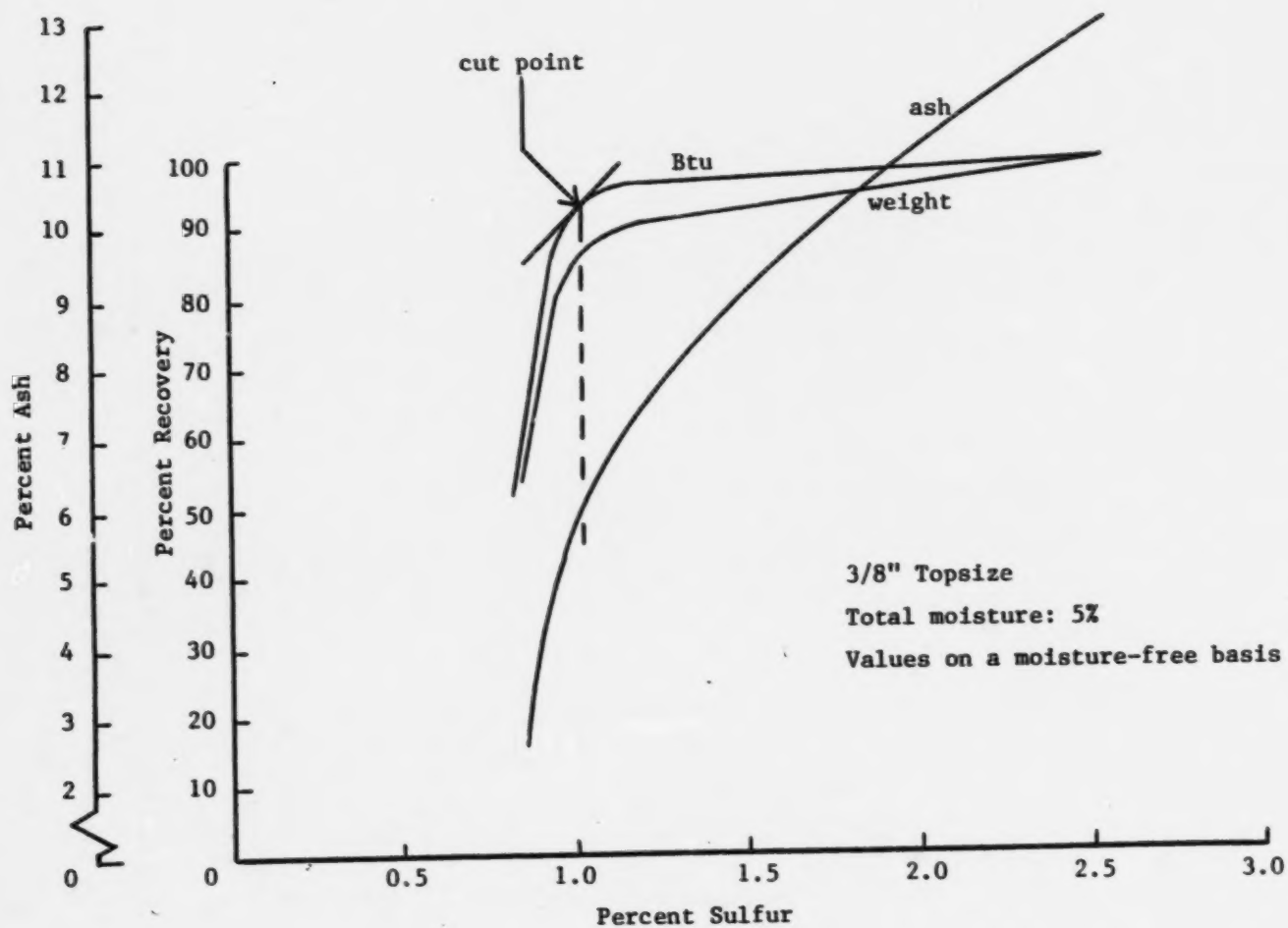


Figure E-6
Washability Curves For Cases 6A and 6C

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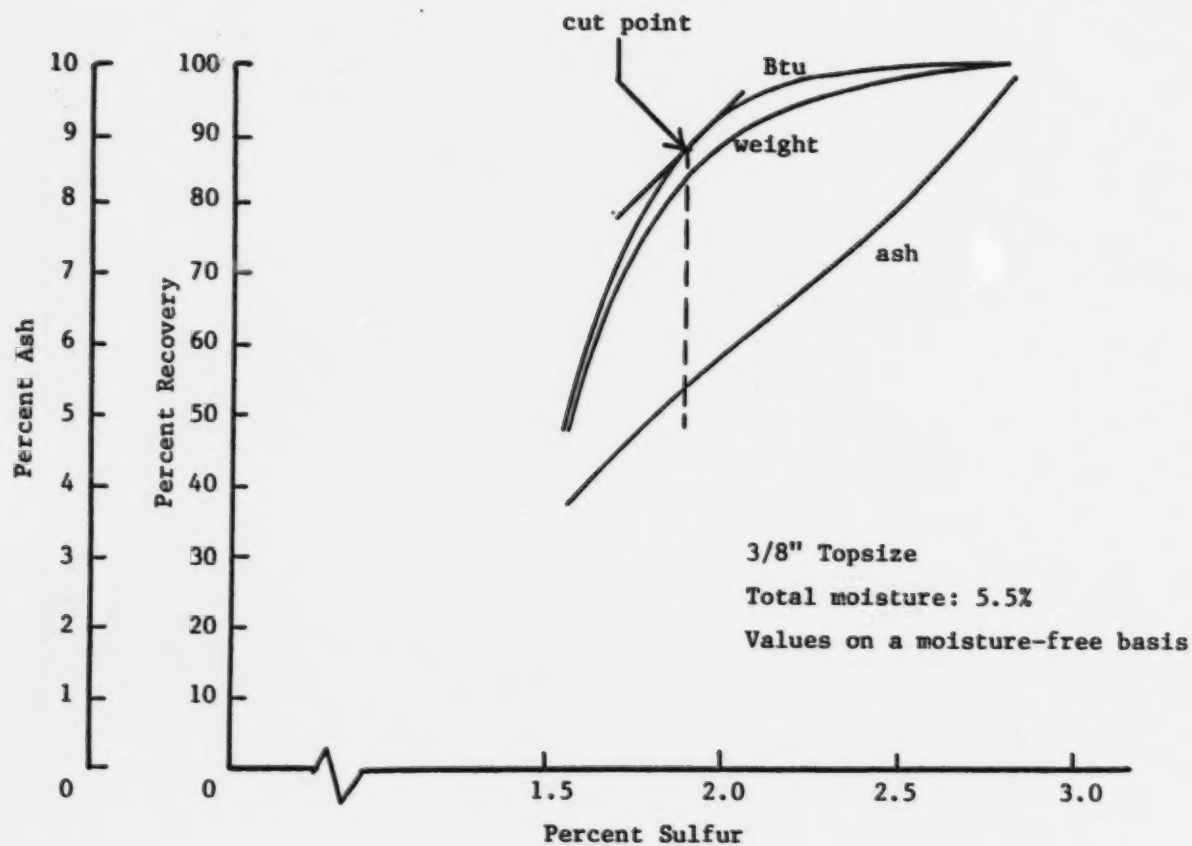


Figure E-7
Washability Curves For Cases 7A and 7C

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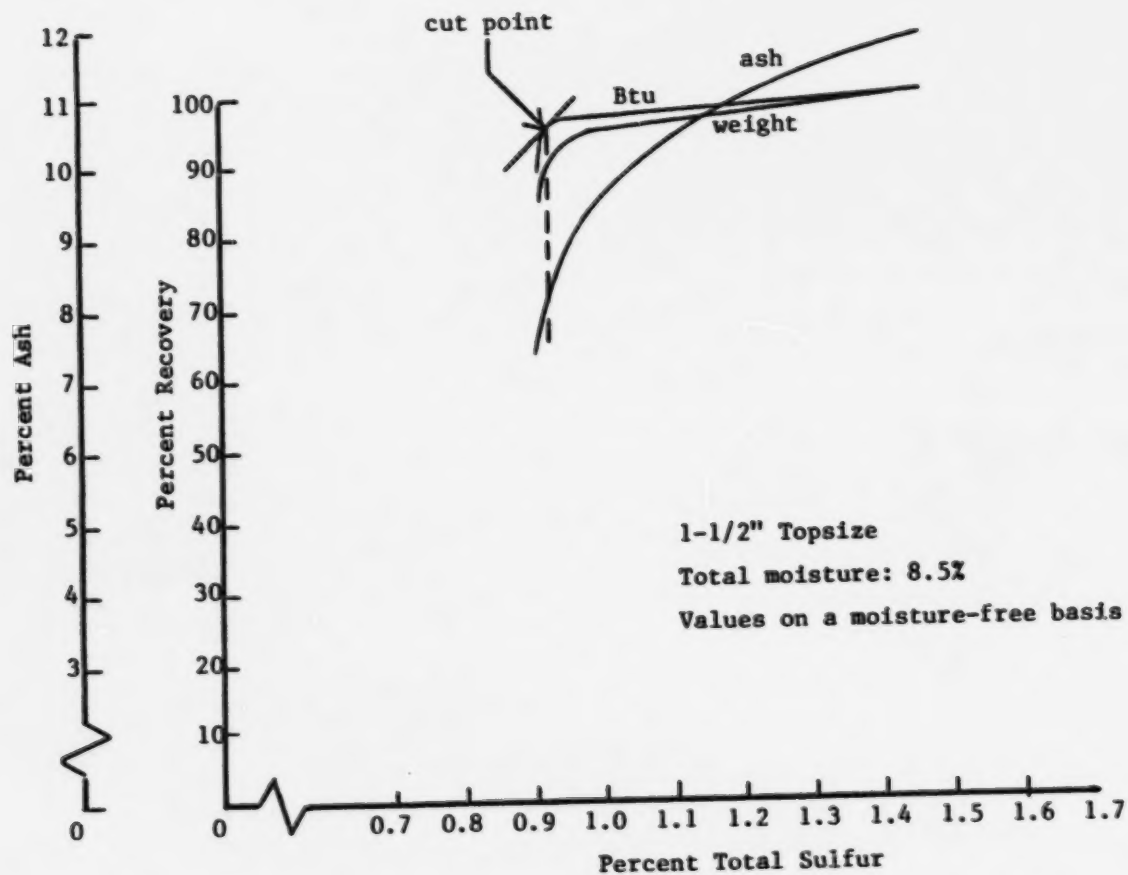


Figure E-8
Washability Curves For Case Studies 8A and 8C

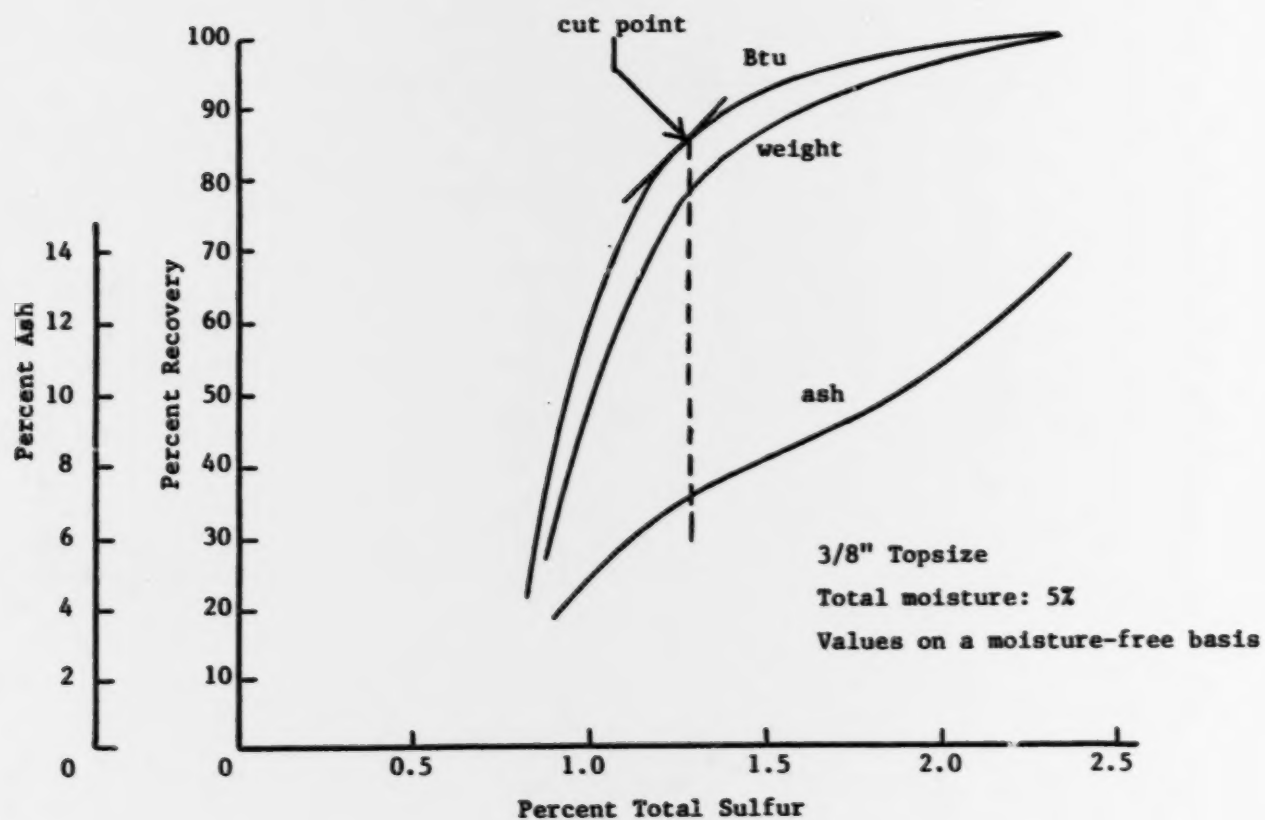


Figure E-9
Washability Curves For Cases 9A and 9C

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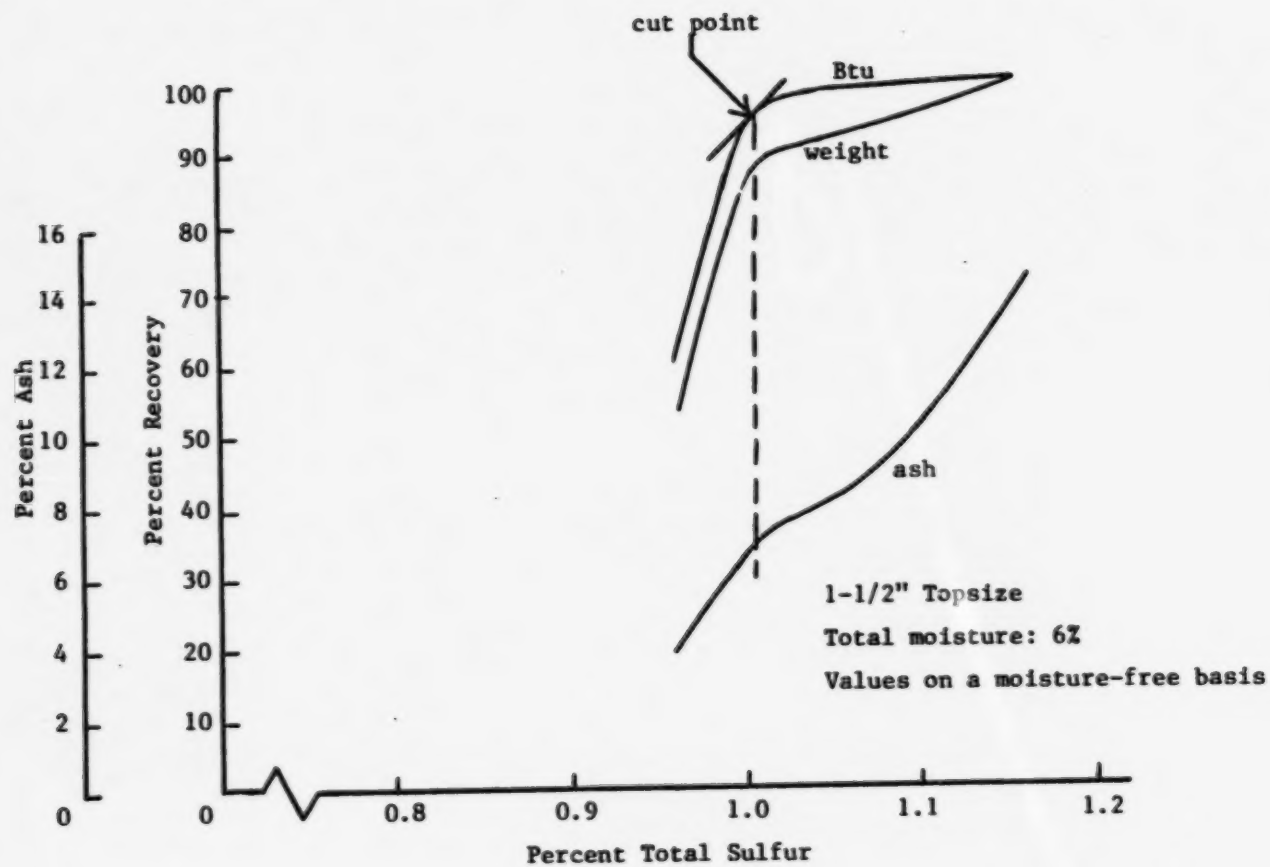


Figure E-10
Washability Curves For Cases 10A and 10C

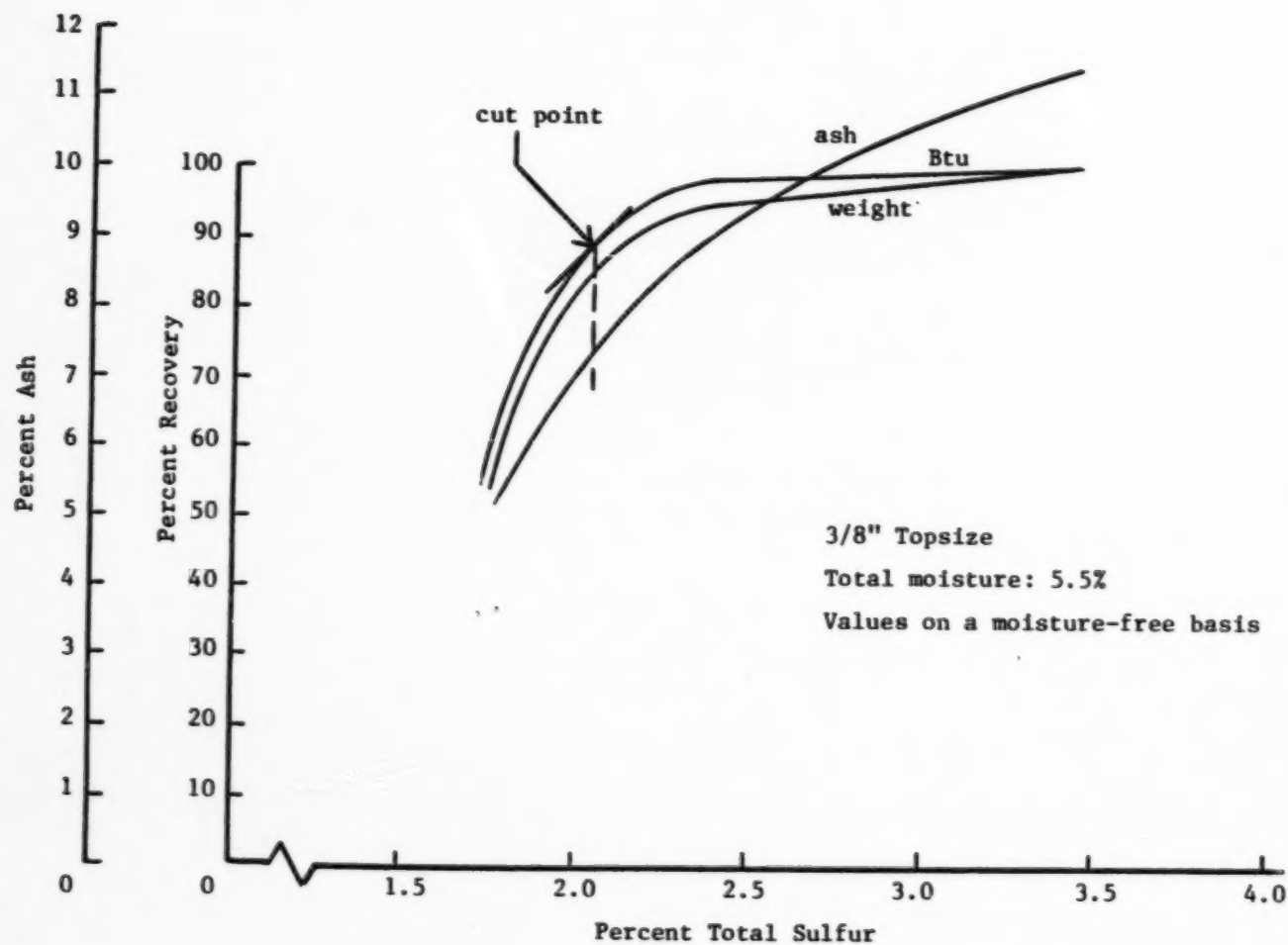


Figure E-11
Washability Curves for Cases 11A and 11C

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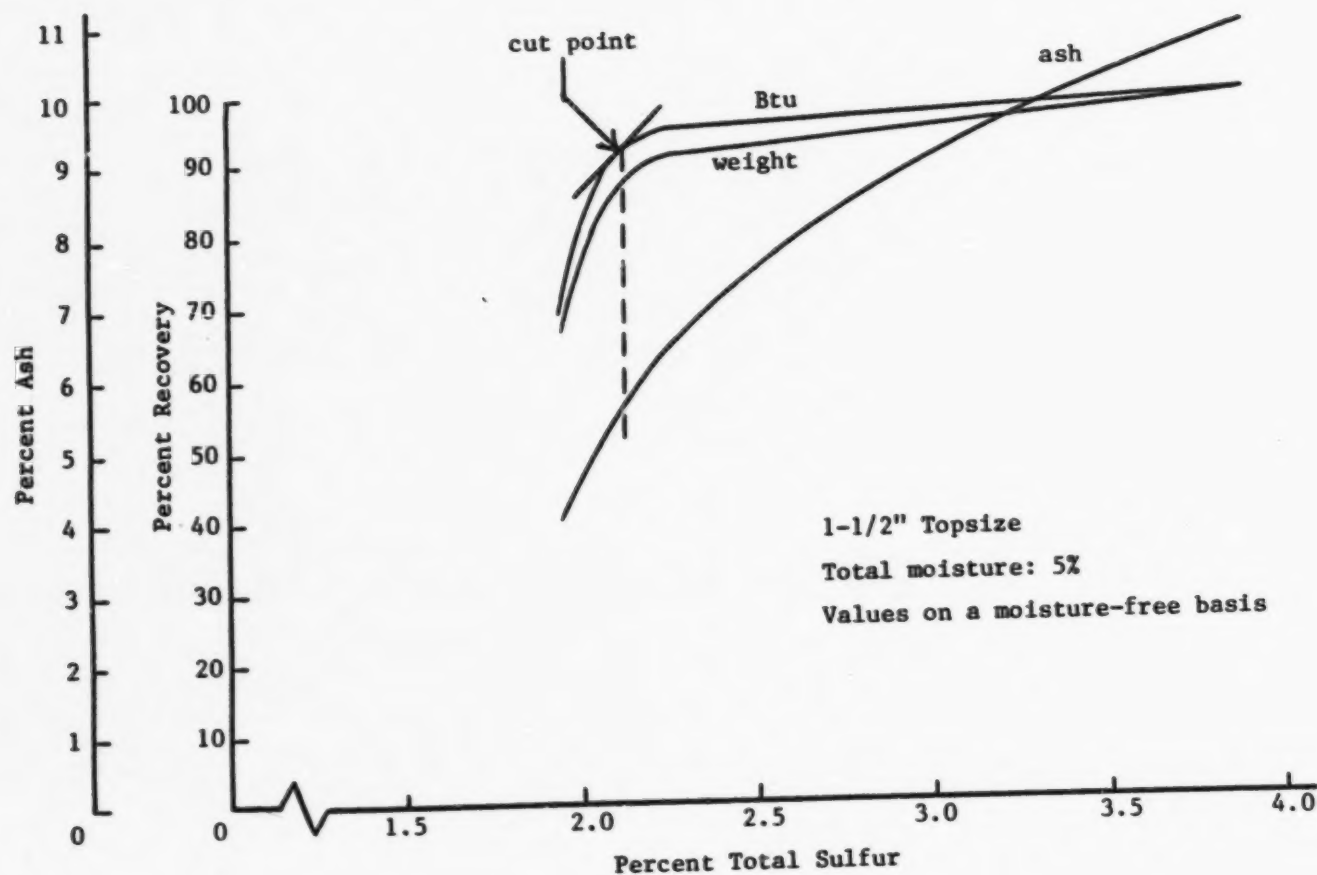


Figure E-12
Washability Curves for Cases 12A and 12C

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APPENDIX F
WORK SHEETS

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CASE I.D. _____

FGD USED ALONE

1.0 CASE CONDITIONS

1.1 Coal Use Area: _____

1.2 Emission Standard: _____

1.3 SO₂ Control Method: Flue Gas Desulfurization (FGD)

1.4 Origin of Coal: State: _____

County: _____ Coalbed: _____

1.5 Raw Coal:

_____ %S _____ % Ash _____ MMBtu/ton _____ lb SO₂/MMBtu

1.6 Assumed Electric Utility Plant: _____ MW_e.

_____ years remaining life,

_____ hrs./year

_____ MMtons/hr.

1.7 Flue Gas Scrubber:

_____ MW_e minimum requirement,

_____ MW_e design size, \$MM _____ capital cost,

_____ % annual cap. chrg., \$MM _____ cap. chrg./yr.

1.8 Flue Gas Reheat:

_____ % of flue gas scrubbed,

_____ % of full scale reheat required,

_____ MMBtu/yr. full reheat, \$ _____/yr. for
full reheat.

2.0 FGD COSTS PER TON OF CLEANED COAL BURNED

2.1 Capital Contribution: \$ _____

2.2 Fuel & Electricity Cost: \$ _____

2.3 O&M Costs:

\$ _____ raw materials (limestone);

\$ _____ operating labor;

\$ _____ maintenance;

\$ _____ miscellaneous.

Total O&M cost per ton of coal burned = \$ _____.

2.4 Flue Gas Reheat Cost: \$ _____

2.5 Total FGD Cost Per Ton of Coal: \$ _____.

2.6 FGD Cost per MMBtu: \$ _____

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CASE I.D. _____
COAL CLEANING COMBINED WITH FGD

- 1.0 CASE CONDITIONS
- 1.1 Coal Use Area: _____
- 1.2 Emission Standard: _____
- 1.3 SO₂ Control Method: _____
- 1.4 Origin of Coal: _____ State: _____
County: _____ Coalbed: _____
- 1.5 Raw Coal: _____ %S, _____ % Ash, _____ MMBtu/ton,
_____ lb. SO₂/MMBtu
- 1.6 Cleaned Coal: _____ % cleaning plant wt. yield, _____
cleaning plant Btu recovery, _____ MMBtu/ton, _____ %S,
_____ % Ash, _____ lb. SO₂/MMBtu, _____ % Btu increase per
unit wt. on cleaning.
- 1.7 Coal Transportation: _____ miles, \$ _____/ton
- 1.8 Assumed Electric Utility Plant: _____ MWe, _____ yrs.
remaining life, _____ hrs./year, _____ MMtons coal/yr.
- 1.9 Utility Ash Disposal Cost: \$ _____/ton
- 1.10 Coal Cleaning Plant: \$ _____/ton/hr. input capacity,
utilized _____ days/yr. @ _____ hrs./day (_____ %
utilization), level payment amortization
- 1.11 Flue Gas Scrubber: _____ MWe minimum requirement, _____ MWe
design size, \$MM _____ capital cost, _____ % annual
cap. chrg., \$MM _____ cap. chrg./yr.
- 1.12 Flue Gas Reheat: _____ % of flue gas scrubbed, _____ % of
full scale reheat required, _____ MMBtu/yr. full reheat,
\$ _____/yr. for full reheat.
- 2.0 ECONOMIC ASSESSMENT
- 2.1 Coal Cleaning Cost Per Ton of Cleaned Coal
- 2.1.1 Cleaning Plant Costs: \$ _____ for amortization,
\$ _____ for O&M

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- 2.1.2 Additional Coal Cost to Provide One Ton of Cleaned Coal. When Mine Operator's Coal Cost is:
\$_____/ton, additional coal cost is \$_____/ton
\$_____/ton, additional coal cost is \$_____/ton
\$_____/ton, additional coal cost is \$_____/ton
- 2.1.3 Cleaning Plant Tax & Insurance Burden: \$_____/ton
- 2.1.4 Total Differential Cost of Mine Operator to Provide One Ton of Cleaned Coal. When the Mine Operator's Cost is:
\$_____/ton, total additional cost is: \$_____
\$_____/ton, total additional cost is: \$_____
\$_____/ton, total additional cost is: \$_____
- 2.2 FGD Costs Per Ton of Cleaned Coal Burned
- 2.2.1 Capital Contribution: \$_____
- 2.2.2 Fuel & Electricity Cost: \$_____
- 2.2.3 O&M Costs: \$_____ raw materials (limestone),
\$_____ operating labor; \$_____ maintenance;
\$_____ miscellaneous. Total O&M cost per ton
of coal burned = \$_____.
- 2.2.4 Flue Gas Reheat Cost: \$_____
- 2.2.5 Total FGD Cost Per Ton of Coal: \$_____
- 2.3 Economic Benefits Per Ton of Cleaned Coal Burned
- 2.3.1 Added Coal Value Per Ton of Cleaned Coal Due to Higher Heat Content. When F.O.B. Mine Raw Coal Price Is
\$_____/ton, added coal value is \$_____/ton
\$_____/ton, added coal value is \$_____/ton
\$_____/ton, added coal value is \$_____/ton
- 2.3.2 Transportation Cost Saving: \$_____/ton
- 2.3.3 Saving in Utility Ash Disposal Cost: \$_____/ton
- 2.3.4 Saving in Utility Coal-Pulverizing Cost: \$_____/ton
- 2.3.5 Saving in Pension Fund Payment: \$_____/ton
- 2.3.6 Saving in Utility Maintenance Cost: \$_____/ton

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2.3.7 Total Benefit Per Ton of Coal Burned. When the F.O.B. Mine Price is:

\$_____/ton, the total benefit is \$_____/ton

\$_____/ton, the total benefit is \$_____/ton

\$_____/ton, the total benefit is \$_____/ton

2.4 Cost Per Ton of Coal Burned to Meet Emission Standards

The differential coal cleaning cost plus FGD cost, less benefits (the overall SO₂ emission control cost) is provided in terms of a) mine operator's raw coal cost (or value) and b) F.O.B. mine raw coal price. This readily indicates the sensitivity of the overall economics to raw coal cost (or value) and to the F.O.B. mine coal price. The assessed overall cost are:

2.4.1 Cost Per Ton of Coal Burned to Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		\$ 30	\$ 40	\$ 50
Mine Operator's Cost	\$	\$	\$	\$
of Raw Coal (Per Ton)	\$	\$	\$	\$
	\$	\$	\$	\$

2.4.2 Cost Per Million Btu Burned to Meet Emission Standard

F.O.B. Mine Raw Coal Price (Per Ton)

		\$ 30	\$ 40	\$ 50
Mine Operator's Cost	\$	\$	\$	\$
of Raw Coal (Per Ton)	\$	\$	\$	\$
	\$	\$	\$	\$

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